Three essays on European electricity markets

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Abstract

This thesis investigates several questions related to the influence of transmission capacities and generation of renewable energy on the outcomes in the wholesale electricity markets. The thesis consists of three self-contained essays that contribute to the policy debate. The analysis of the first essay focuses on a network with strategic firms that can manipulate power flows to their advantage. Methodologically, this chapter belongs to the research literature that represents electricity markets as equilibrium problems with equilibrium constraints. In this framework I compare several policies of enhancing competition and demonstrate that although network expansion can stimulate competition, larger improvements in consumer surplus and welfare can be achieved with restructuring. The second essay is based on a similar model, but in a stylized two node network. This approach demonstrates potential adverse effects (higher prices, lower total consumption, lower consumer surplus) from higher renewable infeed in a network where a region with high renewable potential is separated from a region with high load by a limited transmission capacity. I adopt a worst-case assumption that in each region there is a strategic player exercising its market power. The third essay studies the substitution between transmission and storage expansion - two instruments for the integration of expanding renewable energy. Using a myopic storage heuristic I demonstrate the relatively modest effect of temporal balancing of renewable power. In contrast, transmission expansion has a significant potential in increasing renewable penetration, mitigating curtailment rates, and reducing the minimum conventional generation power at any hour. If Europe is to pursue the high targets of renewable power in electricity consumption, the only way to avoid the expansion of cross border lines is extremely high installed renewable capacities and energy capacities of storage.

Zusammenfassung

Diese Dissertation untersucht Fragen, die sich mit dem Einfluss der Übertragungskapazitäten und der Erzeugung erneuerbarer Energien auf dem Strommarkt befassen. Die Arbeit besteht aus drei eigenständigen Aufsätze, die für die politische Debatte einen Beitrag leisten. Das erste Kapitel konzentriert sich auf ein Netzwerk mit strategischen Unternehmen, die die Stromflüsse zu ihrem Vorteil manipulieren können. Dieses Kapitel gehört zur Forschungsliteratur, die Strommärkte als Gleichgewichtsprobleme mit Gleichgewichtseinschränkungen darstellt. In diesem Rahmen vergleiche ich mehrere Strategien zur Stärkung des Wettbewerbs und zeige, dass der Netzausbau zwar den Wettbewerb ankurbeln kann, mit Umstrukturierungen aber größere Verbesserungen des Verbraucherüberschusses und des Wohlstands erzielt werden können. Das zweite Kapitel basiert auf einem ähnlichen Modell mit einem einfachen Zwei-Knoten-Netzwerk. Dieser Ansatz zeigt mögliche nachteilige Auswirkungen (höhere Preise, geringerer Gesamtverbrauch, geringerer Konsumentenrente) einer höheren Einspeisung erneuerbarer Energie in einem Netz, in dem eine Region mit hohem erneuerbaren Potenzial von einer Region mit hoher Last durch eine begrenzte Übertragungskapazität getrennt ist. Die Annahme ist, dass es in jeder Region einen strategischen Akteur gibt, der seine Marktmacht ausübt. Das dritte Kapitel befasst sich mit der Substitution zwischen Übertragungs- und Speicherkapazitäten - beides Instrumente zur Integration von erneuerbarer Energien. Eine Analyse mit einfachen Speicherheuristik zeigt den relativ bescheidenen Effekt des zeitlichen Ausgleichs. Im Gegensatz dazu birgt die Erweiterung des Übertragungsnetzes ein erhebliches Steigerungspotenzial für die Nutzung erneuerbarer Energiequellen, die Verringerung der Kürzungsraten und die Reduzierung der minimalen konventionellen Stromerzeugung.

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Contents

List of Figures

List of Tables

Introduction

The thesis contains three independent essays, dedicated to different aspects of the European electricity market. Chapter 1 is published in Spiridonova (2016), chapter 2 is a joint work with Franz Hubert.

Recent decades saw a significant transformation of electricity markets in the European Union. The objectives behind European energy policy, driving those changes, are defined by the European Commission (2014d) as competitive pricing, environmental sustainability, and security of energy. The European Commission (2014d) defines a well integrated internal energy market as a fundamental pre-requisite to achieve those objectives in a cost-effective way. Although progress has been made towards an integrated internal energy market, full integration has not yet been achieved (ACER, 2015a).

An integrated internal energy market is impossible to imagine without cross border interconnectors, that provide physical infrastructure for the trade. Compared to the generation capacities of member states, the size of cross border interconnectors is relatively modest. In its report for 2015, the Agency for the Cooperation of Energy Regulators (ACER) states that there is a "lack of adequate and efficient investment in electricity network infrastructure" (ACER, 2015a). The European Commission proposed a 15% interconnection target for 2030, defined as import transmission capacity of a country divided by its installed generation capacity (European Commission, 2018b, 2017b). For most member states this target should not be a challenge, as they are expected to have interconnection level well above 15 % already in 2020. Yet for some countries, including Germany, France, Italy, Spain and Poland, the interconnection level, expected in 2020, is less than 15% (European Commission, 2017a). The size of physical infrastructure is not the only concern - the existing network is not used efficiently. ACER (2017) estimates that in 2016 out of maximum feasible cross-zonal capacity on average only 47% was actually available to the market on high voltage alternating current interconnectors, and 85% on high voltage direct current interconnectors.

The second topic, discussed in this thesis, is the electricity supply from variable renewable energy sources. Between 2005 and 2016, the share of renewables in generation mix of EU-28 grew from 14.8% to 29.6% (European Commission, 2018c). This share is expected to grow further, as the binding final energy consumption target of at least 32% of renewable energy translates into more than 49% of renewables in electricity generation (European

Commission, 2014c, 2018a; European Union, 2018). Since no substantial growth of hydro power is expected (Lehner et al., 2005; Becker et al., 2014), the key role in this expansion will be played by such renewable energy sources as wind and solar. This increasing reliance on renewable energy is aided by the multiple support schemes, employed by member states (European Commission, 2013) and by declining levelized costs of wind and solar power. Fraunhofer ISE (2015) estimates that the costs of solar power will decrease even under conservative assumptions of no technological breakthroughs. The cost reduction is also expected for wind power (Wiser et al., 2016; Agora Energiewende, 2017).

The limited transmission capacities between the countries and the expected growth of renewable penetration give rise to a wide range of issues. This thesis addresses three of them. First, are cross border transmission capacities sufficient to ensure a competitive market? Chapter 1 demonstrates that the answer to this question is negative if large generating companies are assumed to be aware of how to manipulate flows in the network to their advantage. Second, if the trade between regions is restricted by limited transmission capacity, will a higher level of supply from renewable generators always lead to a more competitive market outcome? Chapter 2 demonstrates that insufficient transmission capacity, combined with intermittent supply from renewable generators, may result in a decline of total generation and consumer surplus in the market. Third, given the expansion of installed renewable capacities, to what extent can storage substitute network expansion? Chapter 3 demonstrates that for the realizable potential of pumped storage, the effect of temporal balancing of intermittent renewable generation is relatively modest compared to that of spacial balancing. Analysis in chapters 1-3 can offer additional insights into the functioning of future European network.

The remainder of this section presents extended abstracts for each chapter.

Chapter 1 studies the potential for market power abuse in an integrated European electricity market. The integration of national electricity markets into a single European one is expected to reduce the ability of dominant players to exercise market power. This chapter investigates whether or not existing transmission capacities of cross border interconnectors are sufficient to achieve this result and create vigorous competition in the market. A model with two decision levels is used. On the first level profit maximizing generators play Cournot game against each other. On the last level the system operator clears the market and determines flows in the network to maximize social welfare subject to a set of physical constraints. As each strategic generator anticipates her impact on equilibrium prices and congestion in the system, her optimization problem is subject to equilibrium constraints from the system operator's problem.

The analysis demonstrates that interconnector capacities in Western Europe are insufficient for integration alone to reduce the exercise of market power. I compare several possible competition-enhancing policies: expansion of interconnectors and different scenarios of markets' restructuring. I show that although an increase of line capacity is a useful tool to stimulate competition in an integrated market, it is not a substitute for the restructuring of large players.

Chapter 2 is the joint work with Franz Hubert. Here we explore the implications of increasing renewable supply for the market outcome in transmission constrained network. Many countries are adding substantial capacities of wind and solar based power generation to their portfolio in the process of the de-carbonization of the power industry. While ownership of conventional capacities is typically highly concentrated, renewable energy is often provided by small, independent producers. Hence, one might expect competitive pressure in the electric power industry to increase as renewable energy production is ramped up.

However, energy from renewable sources often has to be transported over long distances and current transmission systems are poorly designed for this task. This is particularly true for wind power produced in coastal areas. In this chapter we show that with insufficient transmission capacities, an increase of wind in-feed in the surplus region might lead to a decline in total generation and consumer surplus in the market. The reason for this somewhat counter-intuitive effect is a switch from an equilibrium in which the market is fully integrated to an equilibrium in which transmission constraint is binding. The resulting fragmentation of the market allows the dominant conventional producers to exploit their local market power more aggressively.

We use a simple two nodes / one line network model. First we explain the anti-competitive effect of increased wind in-feed in more detail. Then we calibrate the model with German data on consumption and transmission and characterize pure and mixed strategy equilibria for various levels of wind in-feed. We find that for a large range of parameters, wind in-feed in the northern surplus region has the potential to aggravate market power and decrease consumer welfare. Finally we discuss measures to mitigate this effect, such as maintaining enough competition among conventional producers and increasing transmission capacity.

Chapter 3 studies the trade-offs related to the integration of expanding renewable energy. Decarbonization, envisioned by the European Union, goes hand in hand with an increasing reliance on such renewable energy sources as wind and solar. Since this energy is inherently intermittent, the future European power systems need to be able to deal with increasing frequency of mismatch between demand for electricity and power generation. Both transmission and storage can be used to address this issue, as they balance intermittent renewable output by shifting surplus generation to deficit regions or to deficit times.

While there is an extensive research literature, that looks for an optimal way to integrate expanding renewable energy, my research focuses on the underlying substitution between transmission and storage expansion. To investigate it, I implement a myopic storage heuristic for various combinations of installed renewable capacity and volume of storage in a network of 19 European countries. I study how certain power system indicators – renewable penetration, curtailment rates, and the minimum conventional back-up – change with (a) installed renewable capacities, (b) energy capacity of storage, and (c) transmission constraints in the network. For a storage capacity limited to 2.6 TWh, which is equivalent to the sum of existing pumped storage capacity and the realizable potential for pumped storage, each indicator demonstrates a relatively modest effect of temporal balancing. In contrast, transmission expansion has a significant potential in mitigating curtailment rates, increasing the penetration of renewable and reducing the need for conventional back-up. These conclusions can offer additional insights for the future network.

Appendix D provides the technical documentation.

Chapter 1

Transmission capacities and competition in Western European electricity market

Abstract

The integration of national electricity markets into a single European one is expected to reduce the ability of dominant players to exercise market power. This paper investigates whether or not existing transmission capacities of cross-border interconnectors are sufficient to achieve this result and create vigorous competition in the market. A model with two decision levels is used. On the first level profit maximizing generators play Cournot game against each other. On the last level the system operator clears the market and determines flows in the network to maximize social welfare subject to a set of physical constraints. As each strategic generator anticipates her impact on equilibrium prices and congestion in the system, her optimization problem is subject to equilibrium constraints from the system operator's problem.

The analysis demonstrates that interconnector capacities in Western Europe are insufficient for integration alone to reduce the exercise of market power. I compare several possible competition-enhancing policies: expansion of interconnectors and different scenarios of national markets' restructuring. I show that although increase of line capacity is a useful tool to stimulate competition in an integrated market, it is not a substitute for the restructuring of large players.

Keywords: electric power market, Stackelberg game, electricity transmission, market power, network expansion

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1.1 Introduction

Energy goals of European Union include affordable and competitive prices, environmental sustainability and security. An integrated energy market is considered a fundamental prerequisite to achieve these objectives in a cost-effective way.[1] In its turn, integration heavily depends on the physical infrastructure used to deliver electric power. The European transmission system, however, was developed in times when regulated regional monopolists dominated the market and cross-border transmission capacities were required only for system reliability. Therefore the adequacy of existing transmission capacities comes into question.

In this paper I focus on the effect the transmission capacities in the network have on competition in the market for electric power. It is expected that an integrated market would have a positive effect on competition. Dozens of generators would compete with each other with no single firm having a significant market share. Since no single generator would be dominant, the ability of firms to exercise market power would be curtailed. Currently the threat of market power abuse cannot be dismissed, as regional market concentration in Europe remains high. Out of 28 member countries of European Union, in 2012 in 23 the market share of the largest generation company was at least 25%, and in nine countries it was above 75%.[2] Such concentration is not likely to disappear any time soon, but it might be mitigated through the integration of regions into a larger market. Although recent developments towards a common market in electric power generation yielded some convergence in wholesale prices, substantial differences remain[3], pointing at insufficient transmission capacities. If the capacities of interconnectors are indeed inadequate to allow for vigorous competition, market power of regional dominant players may not be diminished in an integrated market. This, in turn, would mean that integration without regulation or without restructuring of large companies may not produce the desired competitive market outcome.

To analyze the effect the transmission capacities in the network have on competition in the market for electric power one has to make several modeling assumptions. First, that generating companies are not price-takers. It's impossible to study the potential for market power abuse without considering it. Second, that generating companies take into account the influence they have on flows and congestion. I discuss the models that employ those two assumptions in greater detail in the next section. For the purposes of an introduction it is

[1] See European Commission (2014d).

[2] See European Commission (2014a) and European Commission (2014b).

[3] See Zachmann (2008).

important to note that due to computational difficulties such models were rarely used to analyze real life power markets with large networks. Therefore this paper, with an analysis of an aggregated representation of Western European countries' network, presents a contribution to the energy policy literature. I show potential drawbacks of an integration combined with a complete deregulation, and compare the effects of several possible changes in the market structure that can lead to a more competitive outcome in the integrated market.

The rest of this paper is organized as follows. The second section provides the literature review. The third section describes the mathematical model, the solution approach employed to find Nash equilibrium and the data on the Western European market. The fourth section presents market equilibria in case of oligopoly and, as a benchmark, in case of perfect competition. The analysis shows that existing interconnector capacities are insufficient to reduce market power of dominant players in an integrated market. The fifth section compares two possible competition-enhancing policies: an increase of interconnector capacities and an increase in the number of generation companies. The paper concludes with a discussion of results and their implications for market policy.

1.2 Modeling of electricity markets: literature review

Capacity constraints strengthen market power, as they limit the ability of outside competitors to enter the market. The importance of transmission capacities for competitions in coupled markets has been highlighted in a seminal paper of Borenstein et al. (2000). With insufficient line capacity a strategic generator may find it profitable to restrict her output. This will congest the line into her area of dominance and allow her to exploit market power over the residual demand. But not only a restriction in output can be a profitable way to avoid competition. Cardell et al. (1997) show that a strategic generator can increase her production to congest the line from her area of dominance, prevent competitors from entering her market and therefore be free to exercise market power. As pointed out by Cardell et al. (1997) for a three node example in such a case the total generation in the market will be less compared to the foreclosed competitive outcome.[4] With sufficiently large lines such strategies of congesting lines to avoid competition may no longer be a part of equilibrium. Cardell et al. (1997) emphasize the need for market analysis with realistic models as the profitability of a congesting strategy depends on the exact properties of the network. In general, a sufficiently large

[4] A similar two node result can be found in the appendix of Borenstein et al. (2000), with the examples of asymmetric market equilibria.

increase of transmission capacity merges nodes into one market and strengthens competition between previously monopolistic players. Moreover, one does not necessarily need a lot of transmission capacity to increase competition. As Borenstein et al. (2000) demonstrate, even a relatively small line has a potential to induce Cournot equilibrium between two former monopolists. Surprisingly, this effect does not depend on how much power will actually flow via the line.

In the above mentioned examples profit-maximizing firms take their impact on network operation into account. Another numerical approach to model strategic firms in constrained networks is to assume that generating firms can't correctly anticipate the effect of their output on flows and congestion. Such models are sometimes referred as portraying "naive" generators and are used, for example, in Hobbs (2001) and Tanaka (2009). Compared to models with "non-naive" generators they have an advantage of being formulated as mixed complementarity problems with unique solutions. This significantly simplifies calculations for large networks. A disadvantage of such approach is that it can produce lower price estimates as shown in Neuhoff et al. (2005), thus leading to overly optimistic conclusions. Therefore I assume in this paper that generating companies understand how to manipulate congestion, as, for example in Borenstein et al. (2000).

A power market with strategic generators that can correctly anticipate the effect of their output on flows and congestion and use this knowledge to their advantage can be represented as a two-level game. In terms of timing, first action is taken by strategic generators, who choose their level of output to maximize their profits. Next the system operator maximizes social welfare subject to a set of physical constraints while taking generators' output as given. As each strategic generator correctly anticipates how her choices will influence equilibrium prices and congestion in the system, her optimization problem is subject to equilibrium constraints from the system operator's problem. That is strategic generator's problem of profit maximization includes in itself first order necessary optimality conditions from the system operator's problem as a part of the constraints set. This type of problem, solved by each strategic generator, is known as a mathematical program with equilibrium constraints (MPEC).[5] As there are several strategic producers on the market, finding an equilibrium requires solving a system of MPECs, or an equilibrium problem with equilibrium constraints (EPEC).

Examples of two-level modeling of energy markets can be found, among others, in Cardell et al. (1997), Cunningham et al. (2002), Hu et al. (2004), Ehrenmann (2004), Ralph and Smeers (2006) and Hu and Ralph (2007). As MPECs are, in general, non-convex[6], an EPEC

[5]For a comparison with other approaches in modeling electricity markets see Ventosa et al. (2005).

[6]See, for example, Gabriel et al. (2013) and Hu and Ralph (2007).

might have many or none pure strategy Nash equilibria. Borenstein et al. (2000) demonstrate this problem in the simplest two node network. A number of papers, for example, Fortuny-Amat and McCarl (1981), Gabriel and Leuthold (2010),Ruiz et al. (2012) and Siddiqui and Gabriel (2013) address the challenges of solving an MPEC. As a result of those computational difficulties the two-level approach was rarely used to analyze real life power markets with large networks. For example, Ehrenmann and Neuhoff (2009) and Neuhoff et al. (2005) both use EPECs to analyze the power markets of Northwestern Europe. Ehrenmann and Neuhoff (2009) compare outcome under market coupling and under a coordinated auction of interconnectors, and conclude that market coupling performs better. They point out an important issue: market coupling can produce ambiguous incentives. On the one hand, it can reduce the ability of generators to exercise market power by importing demand elasticity. On the other hand, if companies own generating capacities at several nodes, integration can provide an incentive to increase the exercise of market power. Ehrenmann and Neuhoff (2009) state the balance of those effects can not be determined analytically and needs to be estimated on a real life data. This conclusion stresses the importance of computational analysis for policy estimation.

This paper applies two-level model to an aggregated representation of Western European countries' network. I show potential drawbacks of a complete deregulation and compare the effects of several possible changes in the market structure that can lead to a more competitive outcome in the integrated market. This analysis constitutes the contributions of this paper.

The paper builds on the previous work on two-level models. In particular, in terms of solving each MPEC, I follow the methodology of Gabriel and Leuthold (2010) based on reformulating MPEC as a mixed-integer linear program. The same data set as in Gabriel and Leuthold (2010) is used. The key difference is that Gabriel and Leuthold (2010) model power market of Western Europe as a monopolistic one with just one strategical generating company and the rest behaving as competitive fringe. Although this approach offers some important benchmark results, such market structure assumption may be not very realistic. This paper assumes that Western European power market is oligopolistic with several large generating companies acting strategically.

1.3 Model

As stated in the previous section, interactions in electricity market are represented by a two-level model. First, strategic generators play a Nash-Cournot game against each other and choose their level of output to maximize their profits. Second, the system operator clears the market. It takes generators' output as given and maximizes social welfare subject to a set of physical constraints. The system operator determines flows in the network, load, competitive dispatch and sets the nodal prices. As each strategic generator knows that her choices can influence equilibrium prices and congestion in the system, her profit optimization problem is subject to equilibrium constraints from the system operator's problem. Due to the fact that strategic generators take the flow feasibility constraints into account, if a solution for EPEC exists, it has to be feasible. Congested line in the equilibrium is just a line that is scheduled for use up to its maximum capacity, but not above it. Thus there is no need for redispatch in the model.[7]

To capture loop flows in the network I employ widely applied DC load flow approximation with no losses from Schweppe et al. (1988). The mathematical formulation of the model further is taken from Gabriel and Leuthold (2010), who consider only one strategic player and solve a corresponding MPEC. I assume that the number of strategic players is larger than one. That is, an EPEC is solved to determine the equilibrium in the market.

1.3.1 Mathematical formulation

The notation for the problems is shown below.

Sets:

N	set of nodes
L	set of links
J	set of firms
U	set of generating technologies (types of units)

Indices:

n, k	nodes in the network

[7]Note that here it is assumed that all electricity is traded in a spot market. It has been pointed out by one of the reviewers that a reasonable level of contract cover would massively reduce the incentive to exercise market power. True, such an effect was predicted in the work of Allaz and Vila (1993). Nethertheless, contract cover does not undermine the worst-case outlook of this paper, that strives to see how competitive the integrated market will be even if all regulation fails. From the empirical standpoint, even though one can deduce the amount of electricity traded not on the spot exchange, prices in mutual agreements are unknown. In terms of size of the existing contract cover, comparison of data from European Energy Exchange AG for the bidding area of Germany and Austria with ENTSO-E load data for the same countries tells us that at the end of 2014 in this area about half of the load was traded on the power exchange, there as for France this number was around 10%.

n'	swing node
l	links in the network
j_1	aggregated price-taking firm in the market
j_2 to j_J	strategic firms in the market
u	generating technologies
Parameters:	
a_n, b_n	demand intersect, demand slope at node n ($a_n, b_n \geq 0 \quad \forall n$)
B	Network susceptance matrix of size $n \times n$
H	Network transfer matrix of size $l \times n$
$flow_l^{max}$	transmission capacity of line l
$c_{n,u}$	marginal cost of generation at n with unit u ($c_{n,u} \geq 0 \quad \forall n, u$)
$g_{n,j,u}^{max}$	generation capacity of firm j at node n with unit u
sw	swing bus indicating vector of length N, $sw_{n'} = 1$, $sw_{n \neq n'} = 0$
Variables:	
d_n	quantity consumed at node n
$g_{n,j,u}$	generation by firm j at node n with unit u
p_n	nodal price at node n
δ_k	phase angle at node k

The system operator maximizes total welfare, equal to gross surplus minus generation costs, with respect to a number of constraints.[8] First, in each node energy consumed has to be equal to the sum of generation in that node and net imports from other nodes (1.1b), where net injection (withdrawal) at node n is equal to $\sum_{k \in N} B_{nk}\delta_k$. Second, the flow on each line, equal to $\sum_{k \in N} H_{lk}\delta_k$, is constrained by the transmission capacity (1.1c and 1.1d). Third, output of each firm is limited by its installed generation capacity (1.1e). And finally (1.1f)

[8]One should note that in reality there is a difference between social welfare, equal to the sum of seller and consumer surpluses minus generation costs, and observed surplus as an area between demand and submitted supply curves. The former is unobserved by the system operator. Here system operator is assumed to know the true marginal costs of power generation.

defines a slack bus.

$$\max_{\delta_k, d_n, g_{n,j_1,u}} W = \sum_{n \in N} \left[\left(a_n - \tfrac{1}{2} b_n d_n \right) d_n - \sum_{j \in J, u \in U} c_{n,u} g_{n,j,u} \right] \quad (1.1a)$$

$$s.t. \quad - \sum_{j \in J, u \in U} g_{n,j,u} + \sum_{k \in N} B_{nk} \delta_k + d_n = 0 \quad (p_n) \quad \forall n \quad (1.1b)$$

$$-flow_l^{max} + \sum_{k \in N} H_{lk} \delta_k \leq 0 \quad (\overline{\mu}_l) \quad \forall l \quad (1.1c)$$

$$-flow_l^{max} - \sum_{k \in N} H_{lk} \delta_k \leq 0 \quad (\underline{\mu}_l) \quad \forall l \quad (1.1d)$$

$$g_{n,j,u} - g_{n,j,u}^{max} \leq 0 \quad (\beta_{n,j,u}) \quad (1.1e)$$

$$-sw_n \delta_n = 0 \quad (\gamma_n) \quad (1.1f)$$

$$d_n \geq 0 \quad \forall n \quad (1.1g)$$

$$g_{n,j,u} \geq 0 \quad \forall n, j, u \quad (1.1h)$$

Each strategic generation firm maximizes its profits in Cournot competition subject to its capacity constraint (1.2b) and to equilibrium constraints from system operator's problem (1.2c-2j).

$$\forall j \in \{j_2, J\}, \ \max_{g_{n,j,u}} \Pi_j \left(g_{n,j,u}, g_{n,-j,u} \right) = \sum_{n \in N} \sum_{u \in U} \left[p_n g_{n,j,u} - c_{n,u} g_{n,j,u} \right] \quad (1.2a)$$

$$s.t. \quad g_{n,j,u} - g_{n,j,u}^{max} \leq 0 \quad \forall n, j, u \quad (1.2b)$$

$$0 \leq -a_n + b_n d_n + p_n \perp d_n \geq 0, \quad \forall n \quad (1.2c)$$

$$0 \leq c_{n,j_1,u} - p_n + \beta_{n,j_1,u} \perp g_{n,j_1,u} \geq 0, \quad \forall n, j_1, u \quad (1.2d)$$

$$\sum_{n \in N} B_{nk} p_n + \sum_{l \in L} H_{lk} \overline{\mu}_l - \sum_{l \in L} H_{lk} \underline{\mu}_l - sw \times \gamma_n = 0 \quad \delta_k (free) \quad \forall k \quad (1.2e)$$

$$- \sum_{j \in J, u \in U} g_{n,j,u} + \sum_{k \in N} B_{nk} \delta_k + d_n = 0 \quad p_n (free) \quad \forall n \quad (1.2f)$$

$$0 \leq flow_l^{max} - \sum_{k \in N} H_{lk} \delta_k \perp \overline{\mu}_l \geq 0 \quad \forall l \quad (1.2g)$$

$$0 \leq flow_l^{max} + \sum_{k \in N} H_{lk} \delta_k \perp \underline{\mu}_l \geq 0 \quad \forall l \quad (1.2h)$$

$$0 \leq -g_{n,j_1,u} + g_{n,j_1,u}^{max} \perp \beta_{n,j_1,u} \geq 0, \quad \forall n, j_1, u \quad (1.2i)$$

$$-sw_n \delta_n = 0 \quad (\gamma_n) \quad (1.2j)$$

The solution for the Nash equilibrium is found by diagonalization, a variant of the Gauss-Seidel algorithm for numerical solution of simultaneous equations and the most common[9] strategy for solving an EPEC. The diagonalization substitutes the task of solving EPEC by a task of solving a sequence of MPECs until the decision variables of all strategic players reach a fixed point. In terms of finding a solution for each MPEC, I follow the methodology of Gabriel and Leuthold (2010) based on reformulating MPEC as a mixed-integer linear program (MILP) using disjunctive constraints and linearization.

The steps of Gauss-Seidel algorithm are as follows:

1. First, I define a starting point as a set of initial output levels for all generating companies, a convergence criterion and a maximum number of iterations;
2. For each iteration i j-th strategic generator updates its optimal strategy given the best responses found at iteration i for strategic generators from 1 to $(j-1)$ and the best responses found at iteration $i-1$ for strategic generators from $(j+1)$ to J;
3. Convergence is reached if for all generating companies the absolute difference between the best respose generation levels found in iteration i and the ones found in iteration $i-1$ is less or equal to convergence criterion, otherwise the algorithm fails to converge.

As was mentioned above, the EPEC may not have any pure strategy Nash equilibrium or may have multiple equilibria. Therefore I use multiple starting points.[10],[11]

1.3.2 Model calibration

The research is carried out on the same data set as in Gabriel and Leuthold (2010). Following Gabriel and Leuthold (2010), I refer to the market of several Western European countries,

[9]See Gabriel et al. (2013), chapter 7.

[10]The number of starting points studied is equal to 3 to the power of (number of strategic generators - 1). I consider 3 possible levels at which the output of every strategic firm can be fixed in the starting point. Those levels are: autonomous monopoly output, output of a monopoly on the residual demand with every line being congested into the node, output of a monopoly with every line being congested out of the node (optimal passive and optimal aggressive output in the terminology of Borenstein et al. (2000)). Some of the starting points are identical due to the restrictions imposed by installed generation capacity.

[11]Calculations were performed in GAMS using CPLEX solver. As a test the code successfully replicated results for a simple network with two nodes, one line and two strategic players from Borenstein et al. (2000). Tests for different scenarios presented in sections 4 and 5 took between 36 minutes and 100 hours on an Intel Xeon CPU E5-2620 with 16 GB RAM.

described by the data, as to the Western European one. There are seven country nodes: Belgium (nodes n3 and n6), France (n2), Germany (n1), and the Netherlands (n4, n5, and n7). Auxiliary eight nodes have no supply and demand and are used to model different cross border transmission lines. I consider five generation companies: E.ON (EON), RWE, Electricité de France (EDF), Electrabel (EBEL) and the competitive fringe, aggregated for convenience into one player j1. Generating capacities are divided into 8 types: nuclear, lignite, coal, combined cycle gas turbine (CCGT), gas, oil, hydro and pump. Installed generation capacities and information on marginal costs can be found in table 1.1, the map of the aggregated network in figure 1.1, and the line capacities in table A.1 in the appendix A.1.

As described in section 1.3, there is a linear demand function in the model. For the results to be comparable with Gabriel and Leuthold (2010), I use the same demand data from the Union for the Coordination of Transmission of Electricity (UCTE). The detailed description of demand methodology can be found in Leuthold et al. (2008). To construct a linear demand function reference levels for price and demand were obtained by calculating average spot market price and consumption in 2003, and elasticity of -0.25 was assumed at reference point. Only one average hour is considered, and all results - price, generation, consumer surplus, welfare and profits - refer to hourly values.[12]

[12]To see how the equilibrium in oligopoly can depend on the assumptions used see Neuhoff et al. (2005), page 508, figure 6, results labelled “Responsive T allocation”. Neuhoff et al. (2005) use a slightly different representation of the same Western European market, in particular, they consider 8 strategic players, separate summer and winter demand scenarios, and linearized marginal costs functions. Compared to results in this paper, nodal prices in Neuhoff et al. (2005) are approximately the same for Germany, slightly higher for the Netherlands, about 30% higher for France and about 50-60% higher for Belgium. Seasonal effects are the likely explanation for the difference in French and Belgian prices - Neuhoff et al. (2005) report prices averaged over summer scenarios, while demand function in this paper represents just one average hour per a year. Hence results in this paper do not refer to a peak demand scenario, and potential for market power is not overestimated. The fact that Neuhoff et al. (2005) consider 8 strategic players does not change results significantly: increasing number of firms in already competitive Germany has almost no effect, and having a small additional strategic player in France does not lead to a reduction in French prices.

Figure 1.1: Network map: links and nodes in Western Europe; based on Gabriel and Leuthold (2010) and Neuhoff et al. (2005)

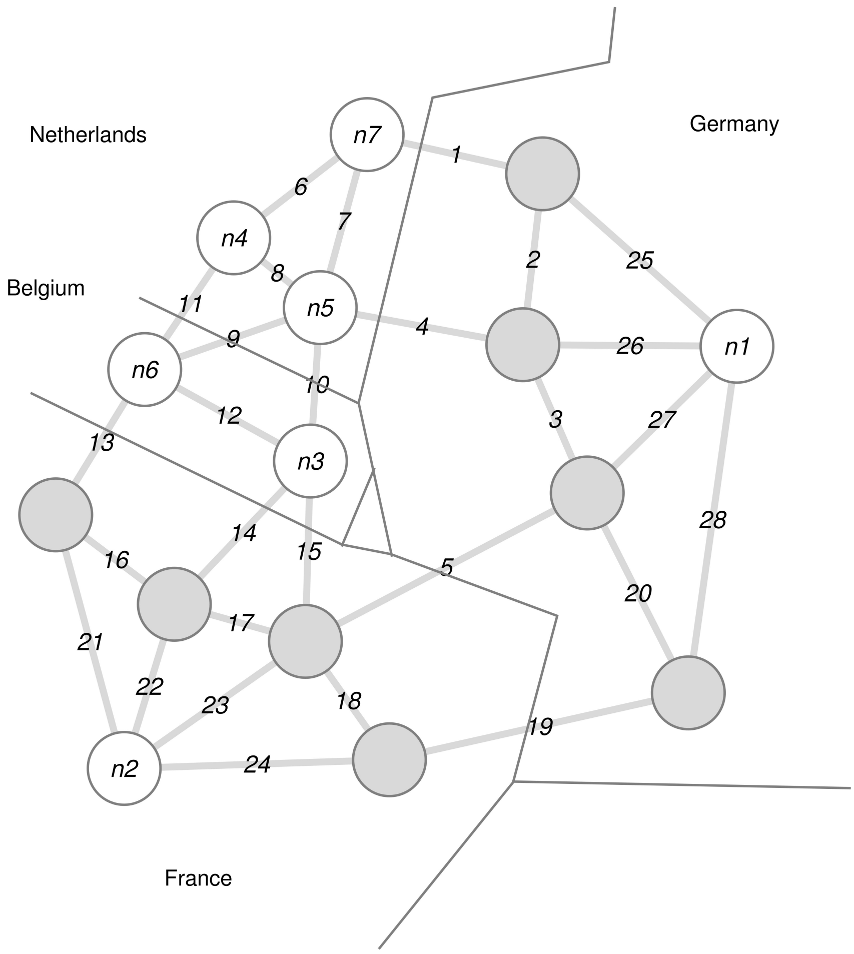


Table 1.1: Generation capacities (GW) and marginal costs per technology (€/MWh) in the fifteen-node Western European network. Source: Gabriel and Leuthold (2010)

	nuclear	lignite	coal	CCGT	gas	oil	hydro	pump	
marginal costs	10	20	22	30	45	60	0	35	
	generation capacities of a company in the specified node								total
Germany									
n1.EON	8	1	7	0	4	3	0	1	24
n1.RWE	6	11	3	2	2	1	0	0	25
n1.j1	6	9	19	6	5	2	1	5	53
France									
n2.EDF	58	1	16	0	0	11	14	3	103
Belgium									
n3.EBEL	3	0	2	0	1	1	0	1	8
n6.EBEL	3	0	1	1	1	2	0	0	8
Netherlands									
n4.EON	0	0	1	0	1	0	0	0	2
n4.EBEL	0	0	1	0	0	0	0	0	1
n4.j1	0	0	2	0	4	0	0	0	6
n5.j1	0	0	0	0	2	0	0	0	2
n7.EBEL	0	0	0	2	2	0	0	0	4
n7.j1	0	0	0	0	1	0	0	0	1

1.4 Equilibrium outcome in Western European market

This section presents equilibria found in the model of an integrated Western European market. In order to explore the potential for market power abuse, I assume that four generating firms - EON, RWE, EDF, EBEL - act strategically when bidding their output. The output of an aggregated price-taking player is determined by the system operator. An important note concerns EDF. The sheer size of this French company gives it a decisive role in determining the market outcome. Therefore it is reasonable to consider EDF to be strategic, even thought it is owned almost completely by French government.[13] Such an assessment provides us with a worst-case outlook, where EDF strives to maximize its profits in the absence, or with a complete failure of regulation.[14] One of the ideas behind the integration is that in a large, integrated market big national players are forced to compete with each other and the need for regulation is reduced. Thus the assumption about an absence of regulation is justified.

To identify the two effects - of line capacity and of market structure - on competition, I look at four scenarios: oligopoly and perfect competition in constrained and unconstrained networks. Perfect competition results in a constrained network are taken from Gabriel and Leuthold (2010), perfect competition results in an unconstrained were calculated based on the code from Gabriel and Leuthold (2010) with transmission constraints ignored in the calculation. Table 1.2 provides a comparison of nodal generation and nodal prices for these four cases. Columns titled “constrained” refer to the equilibria found given the existing interconnector capacities in the Western Europe, while those titled “unconstrained” - to the hypothetical situation when interconnectors can accommodate any possible flows. Consumer surpluses and welfare levels are presented in tables A.4 and A.5, firms’ profits - in A.6.

The model assumes that generating companies know that they can manipulate flows and congestion in the network to their advantage. This leads to non-continuous best response functions of each company to the output of others, which in turn leads to a possibility for multiplicity or non-existence of pure strategy Nash equilibria. In all cases considered I have always found at least one equilibrium. In some cases different starting points lead to slightly different equilibria. Due to the insignificant difference between these equilibria a plausible

[13]EDF used to be a completely state-owned corporation until the end of 2005. As of the end of 2014, the french government retains 84.5% of shares. See the shareholding structure on the web page of EDF: https://www.edf.fr/en/the-edf-group/dedicated-sections/finance/financial-information/the-edf-share/shareholding-structure

[14]As a benchmark, the last two columns of tables A.2 and A.3 report the market equilibrium for the case when EDF behaves as a price-taker while EON, RWE, EBEL act strategically when bidding their output.

Table 1.2: Nodal generation (gen, GW) and nodal prices (€/MWh) in constrained and unconstrained network

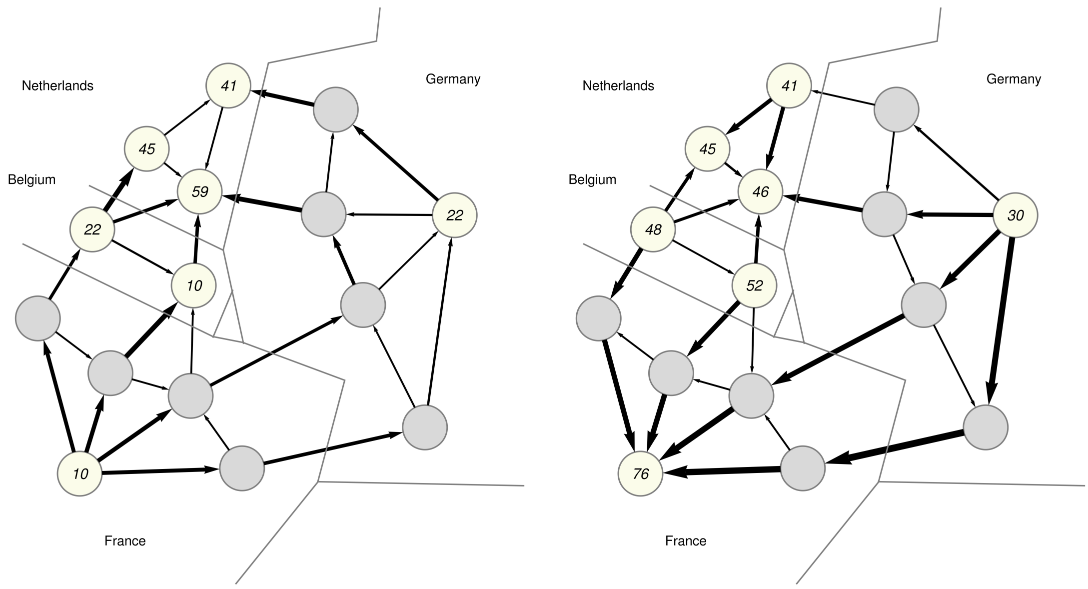
	perfect competition				oligopoly			
	(1)		(2)		(3)		(4)	
	constrained		unconstrained		constrained		unconstrained	
	gen	price	gen	price	gen	price	gen	price
$n1$, Germany	62.2	22.0	61.7	22.0	61.3	30.0	71.0	30.0
$n2$, France	66.0	10.0	73.0	22.0	29.0	76.0	47.0	30.0
$n3$, Belgium	2.5	10.0	3.0	22.0	4.0	52.0	5.0	30.0
$n6$, Belgium	3.5	22.0	3.0	22.0	4.0	48.0	4.0	30.0
$n4$, Netherlands	4.6	45.0	0.1	22.0	4.3	45.0	4.0	30.0
$n5$, Netherlands	2.0	59.4	0	22.0	2.0	45.6	0	30.0
$n7$, Netherlands	2.0	41.4	0	22.0	4.0	41.4	1.0	30.0

explanation is that they are a product of discretization of the generation decisions by strategic players. Once the step of discretization is decreased, those equilibria tend to converge to a single one. Therefore such multiple equilibria are treated as economically equivalent. In other cases multiple equilibria have similar nodal prices and outputs, but are different in the amount of power generated by different companies in each node. For example, for the constrained oligopoly case (3) the total amount of power generated in Germany is the same in all the equilibria, but in some equilibria EON produces more in Germany than in other, leaving a smaller part of the German market for RWE. Nodal prices, nodal generation, nodal consumption and flows remain the same. As the focus of this paper is on international, rather than intranational competition, I do not distinguish between such equilibria and report only total nodal generation and nodal prices. In figures 1.2 - 1.5 arrows indicate the direction of the power flow. The thicker the arrow, the larger the flow is.

In section 1.2 I stated the key difference between this paper and Gabriel and Leuthold (2010), from which the algorithm for solving each MPEC is taken: Gabriel and Leuthold (2010) model power market of Western Europe as a monopolistic with just one strategic generating company and the rest behaving as competitive fringe. Table A.7 shows the influence the assumption about the number of strategic players has on the equilibrium outcome. This influence is especially noticeable for France and Belgium, as far more market power is exercised in those countries in oligopoly compared to the cases when only local producer - EDF or EBEL

Figure 1.2: Power flows and nodal prices (€/MWh) in perfect competition and oligopoly

1.2 (a) in perfect competition   1.2 (b) in oligopoly



- acts strategically. For more competitive Germany and the Netherlands the difference is less prominent.

1.4.1 Strategic vs. competitive firms in unconstrained network

First of all, consider the effect the strategic behavior of large generating companies has in unconstrained network. Compare the perfect competition outcome in column (2) of table 1.2 to the oligopoly outcome in column (4) of the same table. This hypothetical benchmark case shows us how market power, not enhanced by limited transmission capacity, affects the outcome. Unlimited transmission capacities mean that congestion and market separation are not possible, hence nodal prices are the same in the entire network. In unconstrained oligopoly prices increase by 36.4%, from 22 €/MWh to 30 €/MWh, but generation decreases only in France. The reduction of output by EDF pushes prices up, creating a possibility for other players to profit by increasing their generation with low cost technologies. As lines are unconstrained, export is only limited by the amount of installed generation capacities with low enough marginal costs. In equilibrium power flows are directed into France and the Netherlands, where most of the generating units have marginal costs larger than the price. Both nodal consumer surplus and nodal welfare decrease in oligopoly, with an exception of welfare increase in France - here the reduction in generation costs due to the reduced output outweighs the reduction in gross surplus.

1.4.2 Strategic vs. competitive firms in constrained network

Next consider the same effect of strategic behavior of large generating companies compared to a perfectly competitive outcome but in the constrained network. Comparing columns for the constrained perfect competition case (1) and the constrained oligopoly case (3) gives an idea of how the exercise of market power by dominant players shifts the equilibrium away from the first-best solution. Not surprisingly, this shift is smaller in the nodes that have a significant share of fringe suppliers. Take Germany and France. In Germany the competitive fringe produces about 50% of power in both the competitive and the oligopolistic equilibria. In oligopoly German generation level slightly decreases, while the price rises by 36.4%, from 22 €/MWh to 30 €/MWh. At the same time in France EDF cuts down its generation by 56%, from 66.0 GW to 29.0 GW, causing the price to increase by a factor of 7.6 from 10 €/MWh to 76 €/MWh. Market power abuse has different consequences for the smaller national markets of Belgium and the Netherlands. In Belgium the strategic behavior of EBEL leads to increases in both price and generation levels. This is due to the fact that despite the price increase, Belgian electricity is still cheaper than French. Therefore part of it is exported by the system operator into France, congesting French-Belgium interconnectors. As expected, in constrained oligopoly (3), compared to constrained perfect competition (1), firms' profits rise, while consumer surpluses and welfare decrease. But there is an exception - the Netherlands.

In contrast to other countries, Dutch consumers are not worse-off in oligopoly. Moreover, in node n5 they are better-off, as the price drops by 23.1% and consumer surplus increases by 32,7%. There are no strategic players in this node to exercise their market power. The beneficial effect in oligopoly comes from a larger incoming power flow, as the strategic behavior in the rest of the network changes flow pattern.

Different factors are at work in nodes n4 and n7, where prices and consumer surpluses remain the same.[15] Prices do not rise here as strategic players have to take into account the presence of competitive fringe. If dominant generators would decide to cut their output, prices would rise making generation facilities of price-taking firms profitable despite their high marginal cost. Price-taking firms would then have an incentive to increase their production, and strategic players would have to compete with them. In a sense, in those nodes first best

[15] There is a 0.67% consumer surplus decrease in node n7.

prices are maintained in oligopoly due to a decision of dominant players to avoid competition.

1.4.3 Strategic firms in constrained vs. unconstrained networks

The effect of line capacity on competition is central for this study. Limited transmission capacities can enhance market power of local produces, or they can be sufficient enough to effectively merge markets and suppress market power of local produces. If all the national markets considered were to become one fully integrated market, that would mean a Cournot competition with unlimited line capacities[16], that is the unconstrained oligopoly case (4). The closer the results of the constrained oligopoly (3) case are to those in case (4), the more competitive the integrated market is.

In the constrained network French monopolist EDF is separated from other competitors by interconnectors with limited transmission capacities. Free to exercise its market power, it cuts down the generation to 29.0 GWh, compared to 47 GWh in the hypothetical unconstrained network. This substantial reduction of output in the large French market together with constrained transmission capacities limits total import/export possibilities in the network. Limited import/export possibilities in turn create an incentive for an increase in generation in the Netherlands, as higher prices make more expensive generation technologies profitable. Therefore, as markets of Belgium and Netherlands experience price increases compared to the case (4), generation decreases only in one node n3.

In total, existing interconnector capacities enhance market power. Large national players are able to set prices 38 - 153.3% higher compared to the market outcome in unconstrained oligopoly. The only exception with unchanged prices and consumer surplus is Germany with its large market share of competitive firms. Total consumer surplus in the network falls by 29.1%, welfare - by 10.0%. Those numbers reflect the potential for improvement of market outcome by stimulating competition and demonstrate that in a completely deregulated market with four large generating companies acting strategically, their market power will not be diminished by integration. Market power will be exercised as existing interconnector capacities are insufficient to merge national markets into a single one. Without regulation integration will fail to create a competitive market.

[16]See Borenstein et al. (2000) for a example with two monopolists.

1.5 Stimulating competition

Since integration will not effectively curb market power of dominant players, further measures would be required to strengthen competition. In the following section I evaluate the effects of two possible policies: an increase of interconnector capacities and an increase in the number of generation companies.

Expansion of interconnectors starts with answering a question which interconnectors should be expanded and by how much. I focus on the welfare effect from expanding congested lines. A similar approach was employed, for example, by Borenstein et al. (2000), who analyze the impact from increasing the capacity of a congested transmission line known as path 15 on the equilibrium in the electricity market in California. One should keep in mind that in a loop flow environment it is possible that a change (an increase or a decrease) in transmission capacities of uncongested lines can lead to welfare gains. Unfortunately, the search for the socially optimal network structure would add to the model a third level and, with it, substantial complexity to the calculation. Therefore I look at a specific project of expanding congested lines.[17]

Increasing the number of generation companies is another way to intensify competition. The increase can be achieved by stimulating entry or by division of a large existing players into several independent ones. I consider the second option and propose a division plan inspired by market restructuring in UK in 1990, when the generating capacities of the monopolistic Central Electricity Generating Board were divided in three parts: one nuclear-only company and two non-nuclear companies.[18] The resulting market has been described as duopoly, as the state owned Nuclear Electric supplied base load at a price below that of two dominant

[17]A more general approach is to identify the socially optimal network structure. As a benchmark, imagine we forgo discussing all the existing or possible political institutions and focus on a simple case of centralized benevolent planning. Then the two-level model with strategic system operator and strategic generating companies needs to be complemented by a new decision level with a benevolent planner. The planner knows the impact transmission capacities have on the market equlibrium (or equilibria) and looks for a socially optimal network in the earliest time period. The three stage model represents the idea of proactive transmission planning by Sauma and Oren (2006), Pozo et al. (2013a) and Pozo et al. (2013b). Unfortunately, the third decision level adds substantial complexity to the calculations. To avoid it, in all the mentioned papers the market for generation is considered to be perfectly competitive. Such an assumption makes it impossible to study the effect the transmission capacities have on competition between strategic generators. Therefore it is unsuitable for the purposes of this paper.

[18]See, for example, Wolfram (1999) and Woo et al. (2003).

players.[19] In the Western European market EDF is a clear candidate for the division. The largest national markets in the model are Germany and France. They have approximately the same amount of installed generation capacities (see table 1.1), but while German market has two almost equal-sized strategic players and a competitive fringe with half of the total market share, French market is monopolistic. Further in this section I propose the division of EDF in three independent companies: one with all the nuclear generation capacities, and two each with a half of all other generation capacities.

Further subsections discuss and compare three options for reduction of market power in an integrated and deregulated Western European market: an expansion of interconnectors; a restructuring of the French monopolist EDF with a complete privatization; a restructuring of EDF with partial privatization and selective regulation of state owned nuclear generation. In section 1.4 I have mentioned that a full integration of all Western European national markets would be equivalent to the case of Cournot competition with unlimited line capacities. Although large players act strategically in this hypothetical case of unconstrained oligopoly, they have no possibility to exploit transmission constraints to their advantage. For this reason the three proposed policies are compared (1) to the equilibrium in the constrained oligopoly, (2) between each over, and (3) to the equilibrium in oligopoly with no transmission constraints.

Tables A.2 - A.6 in Appendices A.2 and A.3 provide values for the found market outcomes.

1.5.1 Expansion of interconnectors

In the deregulated Western European market three lines would be congested in the equilibrium as a result of the strategic behavior of four large generating companies. These lines are: l10 (congested from Belgium to the Netherlands), l13 (congested from Belgium to France) and l19 (congested from Germany to France). This subsection describes the equilibrium with transmission constrains relaxed on these three lines, that is after they have been expanded sufficiently enough to accommodate any potential power flows. The market outcome for this case is presented in the table 1.3. The costs of network expansion are ignored. Once the ex-

[19]Several studies found evidence of market power abuse by two private generators. Green and Newbery (1992) argue that the two firms were able to bid electricity with a high markup and manipulated market by exploiting transmission constraints in the grid, while the Nash equilibrium with five firms would have been more competitive. Newbery and Pollitt (1997) believe that creating more successor companies would have improved the distribution of the net benefits and increased social welfare. On the other hand, Wolfram (1999) showed that although prices after restructuring were higher than marginal costs, the exercise of market power was not nearly as severe as most theoretical predictions.

Table 1.3: Nodal generation (gen, GW) and nodal prices (€/MWh) in oligopoly

	unconstrained		constrained		relaxed	
	gen	price	gen	price	gen	price
$n1$, Germany	71.0	30.0	61.3	30.0	62.3	30.0
$n2$, France	47.0	30.0	29.0	76.0	30.0	71.0
$n3$, Belgium	5.0	30.0	4.0	52.0	3.0	58.9
$n6$, Belgium	4.0	30.0	4.0	48.0	4.0	54.2
$n4$, Netherlands	4.0	30.0	4.3	45.0	8.0	46.5
$n5$, Netherlands	0	30.0	2.0	45.6	1.2	45.0
$n7$, Netherlands	1.0	30.0	4.0	41.4	2.0	40.7

pansion is carried out, total welfare increases by 0.95%, consumer surplus by 2.5%[20], prices in France drop just a little, while prices in Belgium rise. However, there is an issue with the realization of the project.

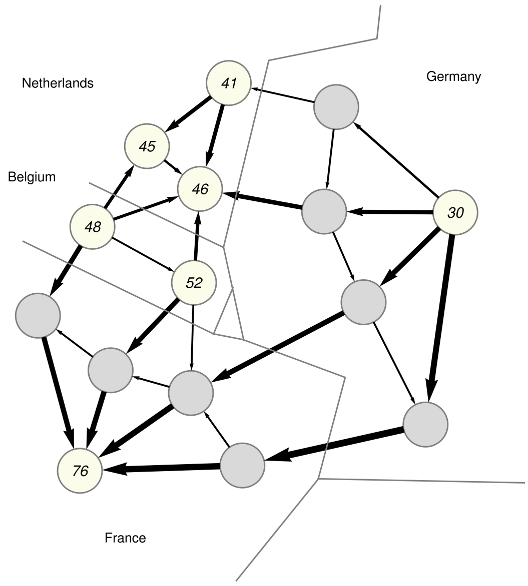
Despite increases in total welfare and in total consumer surplus, Belgian consumers are worse-off compared to the constrained oligopoly case, while EBEL's profits rise. The existence of local winners and losers is an expected consequence of nodal pricing. As consumers in different nodes pay different prices, an increase in a total welfare in the system will not necessarily mean that everybody is better off. One should expect a redistribution of welfare between the players as a result of a change in network structure. Since two of the three expanded lines connect Belgium to its neighbors, Belgian consumers have an incentive to hinder the implementation of the proposed expansion if there are no subsequent welfare transfers. Note that the reduction in Belgian nodal consumer surpluses is greater than the increase in EBEL's profit: total Belgian consumer surplus declines by 26 thousands of euro per hour, while total profit of EBEL across network increases by only 23 thousands of euro per hour. Despite this, a compensating mechanism is attainable, as total consumer surplus increase across the network is larger than the reduction in total profits. The proposed expansion project is possible, but it will require political decisions.

It should be mentioned that "possible" is not equal to "probable". Any cross-country interconnect investment requires coordination between countries involved. An extreme example of coordination failure can be found in the paper of Makkonen et al. (2015), who explore the dependence of infrastructure development on institutional requirements and governance structure. Even in the historically successful Nordic electricity market those dependencies

[20] See tables A.3 and A.4 in the appendix A.2.

Figure 1.3: Power flows and nodal prices (€/MWh) in oligopoly before and after the network expansion

1.3 (a) without line expansion 1.3 (b) with line expansion



have lead to an expansion of Hasle (Westlink) interconnector, considered critical by many, being canceled. Small benefits from the proposed expansion of the three congested lines in the Western European market should be weighted against almost certain high political costs.

1.5.2 Restructuring of French power generation

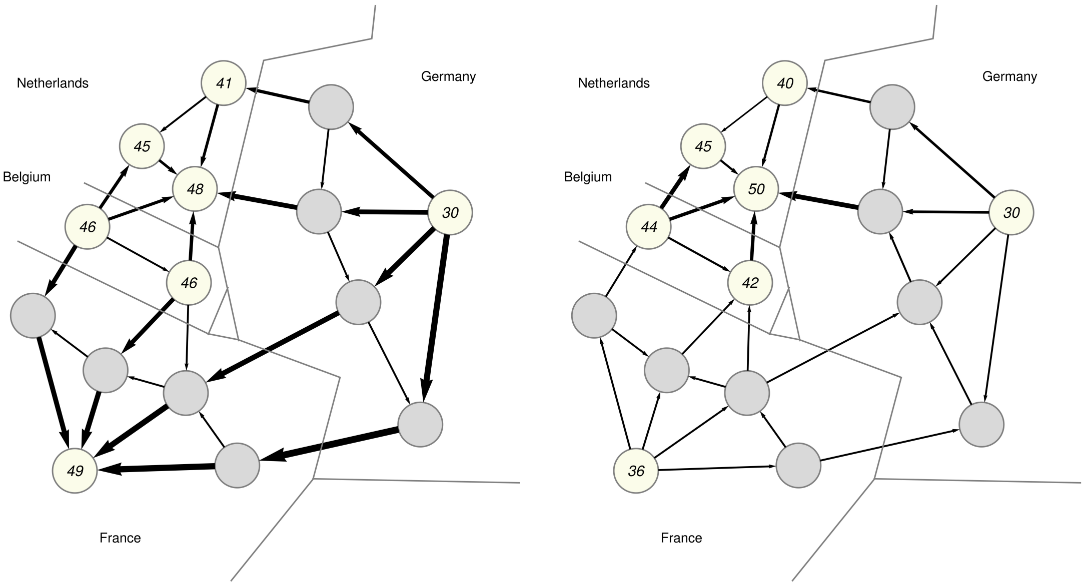
Division of EDF with complete privatization

Another option to increase competition in Western Europe is to restructure French generation sector. Assume EDF is divided into three independent companies: one with all the nuclear power plants, and two each with a half of all other generation capacities. Every successor company is privatized and strategically chooses its level of output so as to maximize its profits in the absence of any regulation. There are two Nash equilibria, listed in table 1.4 and A.2 - A.5 in separate columns. The main result of restructuring with complete privatization is as expected: French consumers benefit while profits of French producers decline, as generation level increases by 43.1-79.3 % and price falls by 36.0-52.7%.

Tables 1.4 and A.2 - A.5 compare the equilibria after restructuring with the equilibrium after

Figure 1.4: Power flows and nodal prices (€/MWh) in oligopoly with division and complete privatization of EDF

1.4 (a) 1^{st} equilibrium 1.4 (b) 2^{nd} equilibrium



line expansion. While line expansion increases total consumer surplus by about 2.5% and total welfare by 0.95% compared to the constrained oligopoly case, the respective numbers for the division and complete privatization of EDF are 19.4-30.4% and 5.8-7.4%. Depending on the equilibrium, this restructuring scenario leads to the total consumer surplus just 7.6-15.4% below the one in the unconstrained oligopoly. Against the same benchmark, in the relaxed equilibrium consumer surplus is smaller by 27.3%, and in the the constrained equilibrium - by 29.1%. Not surprisingly, the improvement is achieved by a significant decrease in the exercise of market power in France.

Division of EDF with partial privatization

Finally, consider a restructuring scenario closer to the reform of the British energy sector. As before, the French monopolist is divided in three independent companies, but now the new nuclear company is not privatized and is kept as a public utility subject to perfectly efficient price regulation. That is, it is considered to be a price-taker whose output in the model is determined by the system operator. RWE, EON, EBEL and two non-nuclear successor companies of EDF strategically choose their level of output so as to maximize their profits in the absence of any regulation.

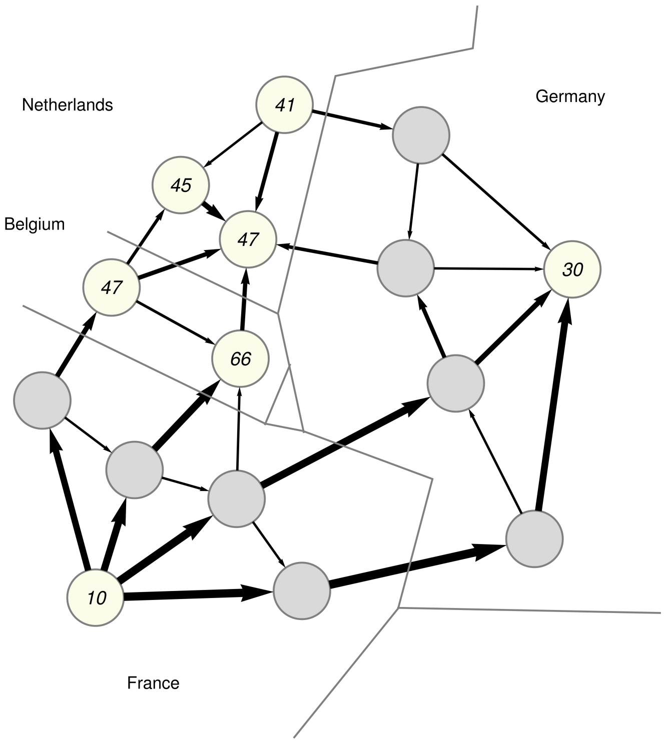
Table 1.4: Nodal generation (gen, GW) and nodal prices (€/MWh) in oligopoly, with two equilibria for the case of complete privatization of EDF

	unconstrained		constrained		privatization of EDF					
					complete				partial	
					1^{st} eq.		2^{nd} eq.			
	gen	price	gen	price	gen	price	gen	price	gen	price
$n1$, Germany	71.0	30.0	61.3	30.0	59.2	30.0	61.8	30.0	55.6	30.0
$n2$, France	47.0	30.0	29.0	76.0	52.0	35.9	41.5	48.6	67.0	10.0
$n3$, Belgium	5.0	30.0	4.0	52.0	2.5	42.5	4.0	46.3	1.0	66.2
$n6$, Belgium	4.0	30.0	4.0	48.0	3.5	43.8	4.0	46.3	2.5	47.3
$n4$, Netherlands	4.0	30.0	4.3	45.0	4.5	45.0	4.8	45.0	5.4	45.0
$n5$, Netherlands	0	30.0	2.0	45.6	2.0	50.2	2.0	47.8	2.0	46.5
$n7$, Netherlands	1.0	30.0	4.0	41.4	3.0	40.2	3.0	40.5	4.0	41.0

In this case there is one Nash equilibrium. As expected, keeping the large nuclear generation capacities as a public utility leads to a more competitive outcome, allowing to attain first-best result in France. Competitive French nuclear power plants work at almost full capacity, while French strategic players only produce with hydro utilities, using them up to full capacity. An important result concerns consumer surpluses, reported in table A.4. French consumer surplus with partial privatization of EDF is higher than in the unconstrained oligopoly case. In other words, such restructuring of French generation leads to greater benefits for French consumers (but lower profits for French generators) than an infinite increase of line capacities. At the same time, market power will still be exercised in Belgium and, to a lesser degree, in the Netherlands.

The difference in the exercise of market power in those two countries is worth mentioning. In the equilibrium generation in Belgium is carried out on the nuclear power plants with marginal costs of 10 €/MWh, whereas in the Netherlands active power plants have marginal costs ranging from 22 €/MWh for coal to 45 €/MWh for gas. Based on this generation structure, one would expect lower prices in Belgium, but market structure differences lead to an opposite result. There are no fringe firms in Belgium, and Dutch-German interconnectors are larger compared to Belgian-French ones. Keep in mind that in the equilibrium nodal price depends on the marginal unit consumed. That unit can be imported depending on the output choices of domestic producers. Given this, one can see from table 1.4 that price markups in Belgium are higher than in the Netherlands, despite the fact that in Belgium there are more

Figure 1.5: Power flows and nodal prices (€/MWh) in oligopoly with divided EDF and regulated nuclear generation



generating capacities with lower marginal costs than in the Netherlands.

Both in terms of total welfare and of total consumer surplus the restructuring of EDF with partial privatization outperforms restructuring of EDF with complete privatization, which in turn outperforms the expansion of lines congested in oligopoly. In terms of total consumer surplus the partial privatization also outperforms an infinite increase in the capacity of every inteconnector in the network.[21]

Similar result have been found in Tanaka (2009) - increasing the bottleneck capacity leads to welfare gains, that are not substantial once expansion costs are taken into account, and that are lower than welfare gains from the divestiture of the largest company. In case of Tanaka (2009), this result is not surprising, as he assumed that generating firms can't correctly anticipate the effect of their output on flows and congestion, i.e in his model generating firms do not exploit transmission constraints in their exercise of market power. In this paper generators are not "naive" and they can exploit transmission constraints to keep competition out of their markets. Given this assumption, one could have expected that expansion of congested lines would have a greater effect on market power and, consequently, on social welfare. As this paper shows, it is not the case. Relieving most pressing, or even all bottlenecks may still be not as beneficial as restructuring.

1.6 Conclusion and policy implications

Integration is expected to make regional dominant players small in the integrated market, thereby enforcing competition without much regulation. Insufficient transmission capacities, however, can prevent full integration of national electricity markets into a singe one, allowing dominant players to continue the exercise of market power.

This paper investigates the potential for an increase of competition in an integrated Western European electricity market. The analysis of market equilibria allows me to conclude that existing interconnector capacities are insufficient to reduce the ability of large national players to exercise market power without regulation. Additional measures are needed to

[21] At the suggestion of one of the reviewers, a robustness check was performed with lower marginal cost for gas generation units, equal to 40 instead of 45 €/MWh. Four scenarios were considered: oligopoly in a constrained network of Western European market, oligopoly in an expanded network, and restructuring of EDF with complete or partial privatization. A change in marginal costs for gas results in just two lines congested in the initial scenario: l13 (congested from Belgium to France) and l19 (congested from Germany to France). Line l10, that was congested from Belgium to the Netherlands with higher marginal cost for gas generation units, is not used up to its maximum capacity in this scenario. Therefore in expanded network only these two lines – l13 and l19 - were assumed to be upgraded sufficiently enough to accommodate any potential power flows. The key conclusion of previous analysis - that both in terms of total welfare and of total consumer surplus restructuring of EDF with partial privatization outperforms restructuring of EDF with complete privatization, which in turn outperforms the expansion of lines congested in oligopoly - holds in the robustness check with lower marginal cost for gas generation units. See table A.8 for the nodal prices, total welfare and total consumer surplus in the network under a different assumption on gas generation units.

enhance competition in the integrated market. The effects from three possible policies are compared: an expansion of interconnectors; a restructuring of French monopolist Electricité de France with complete privatization; and a restructuring of Electricité de France with partial privatization and selective regulation of the nuclear generation.

The comparison of those competition enhancing policies shows the following. First, if the three interconnectors congested in oligopoly would have capacity sufficiently high to accommodate any potential flows, total consumer surplus and total welfare would not increase as much as in case of restructuring of French generation sector. That is, in this example network expansion can not substitute the restructuring. Moreover, the change in the network structure leads to the redistribution of welfare. Political issue of local winners and loosers is further sharpened by the fact that in the considered set-up Belgian consumers are worse-off after the grid upgrade is performed, and two of the expanded lines connect Belgium to the neighboring countries. Thus the implementation of the proposed expansion scenario depends on the existence of welfare transfers in the networks. This example highlights the importance of cross-border investment mechanism. Economic analysis can assess benefits from line expansion, but the institutional framework surrounding cross-border investment decisions will determine the set of feasible expansions projects on the way to a single European market.

Second, restructuring is even more beneficial when combined with regulation. Total consumer surplus and total welfare in Western Europe increase further if French nuclear generation capacities are effectively regulated. Such a restructuring allows to achieve first best price and generation levels in France, the country with the highest exercise of market power under existing market structure and network constrains. Furthermore, this reform leads to the total consumer surplus higher compared to the hypothetical case of oligopoly with unconstrained lines, when strategic players have no possibility to exploit transmission constraints to their advantage. It is important to point out that the costs of both policies – line expansion and restructuring – are left out of the calculation. A rough estimate for the first one can be obtained by multiplying the length of expanded interconnectors by the value of upgrade by grid upgrade costs.[22] In the analysis I have assumed that three lines were expanded enough to accommodate any possible line flows, i.e. in the calculation their capacity was set to be extremely high. If we assume that the capacity of the those lines is at least doubled, estimated cost would be more than 255 million euro. An estimate for the restructuring cost is harder to obtain. But even if network expansion costs would be the same as the costs of restructuring

[22]An estimate for the length of the expanded lines can be made based on ENTSO-E grid map, see ENTSO-E web page: https://www.entsoe.eu/publications/order-maps-and-publications/electronic-grid-maps/Pages/default.aspx. Grid upgrade costs were taken from taken from Fürsch et al. (2013), table A.6

utilities, grid upgrade does not produce the same increase in the social welfare.

These results allow me to conclude that although in an aggregated representation of Western European electricity market an increase of line capacity is a useful tool to stimulate competition in an integrated market, it is not a substitute for the regulation of large players. It is important to note that this analysis has been carried out on a relatively old data set with only one demand scenario. Therefore the results here can't be treated as a base for current policy recommendations, but they rather demonstrate possible outcomes in the network of Western European electricity market. Note that a firm can have a possibility to exercise of market power but may choose not to do so. According to the consumption data from ENTSO-E for 2003, the year the linear demand function is based on, this is exactly what happened: observed market outcome corresponds to the predicted results for the case of division of EDF with complete privatization. Exact present day policy recommendations require a further study on a larger data set, covering more countries and more typical hours, to estimate the exact impact of interconnector capacities on the exercise of market power in the current conditions of European market.

Appendix A

Transmission capacities and competition in Western European electricity market

A.1 Network parameters

Table A.1: Line parameters in the fifteen-node Western European network, source: (Gabriel and Leuthold, 2010)

	line capacities (MW)	reactance (Ω)
l1	2970	12
l2	1840	69
l3	1840	43
l4	900	28
l5	1330	25
l6	1840	33
l7	1840	50
l8	1840	29
l9	640	61
l10	640	42
l11	940	34
l12	1840	31
l13	900	55
l14	1210	45

l15	270	156
l16	2760	22
l17	1840	27
l18	3330	38
l19	1280	11
l20	3330	41
l21	∞	46
l22	∞	46
l23	∞	46
l24	∞	46
l25	∞	46
l26	∞	46
l27	∞	46
l28	∞	46

A.2 Equilibria in the market

First best results in a constrained network are taken from Gabriel and Leuthold (2010), first best results in an unconstrained were calculated based on the code from Gabriel and Leuthold (2010) with transmission constraints ignored in the calculation.

Table A.2: Nodal generation, GWh

	first best		oligopoly							
						privatization of EDF			EDF competitive	
node	constrained	unconstrained	constrained	unconstrained	relaxed	complete		partial	constrained	unconstrained
						1^{st}	2^{nd}			
$n1$, Germany	62.2	61.7	61.3	71.0	62.3	59.2	61.8	55.6	55.6	59.8
$n2$, France	66.0	73.0	29.0	47.0	30.0	52.0	41.5	67.0	67.4	73.0
$n3$, Belgium	2.5	3.0	4.0	5.0	3.0	2.5	4.0	1.0	1.0	3.0
$n6$, Belgium	3.5	3.0	4.0	4.0	4.0	3.5	4.0	2.5	2.5	3.0
$n4$, Netherlands	4.6	0.1	4.3	4.0	8.0	4.5	4.8	5.4	5.4	2.0
$n5$, Netherlands	2.0	0	2.0	0	1.2	2.0	2.0	2.0	2.0	0
$n7$, Netherlands	2.0	0	4.0	1.0	2.0	3.0	3.0	4.0	4.0	0

Table A.3: Nodal prices,€/MWh

	first best		oligopoly							
						privatization of EDF			EDF competitive	
node	constrained	unconstrained	constrained	unconstrained	relaxed	complete		partial	constrained	unconstrained
						1^{st}	2^{nd}			
$n1$, Germany	22.0	22.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	22.0
$n2$, France	10.0	22.0	76.0	30.0	71.0	35.9	48.6	10.0	10.0	22.0
$n3$, Belgium	10.0	22.0	52.0	30.0	58.9	42.5	46.3	66.2	66.2	22.0
$n6$, Belgium	22.0	22.0	48.0	30.0	54.2	43.8	46.3	47.3	47.3	22.0
$n4$, Netherlands	45.0	22.0	45.0	30.0	46.5	45.0	45.0	45.0	45.0	22.0
$n5$, Netherlands	59.3	22.0	45.6	30.0	45.0	50.2	47.8	46.5	46.5	22.0
$n7$, Netherlands	41.4	22.0	41.4	30.0	40.7	40.2	40.5	41.0	41.0	22.0

Table A.4: Hourly consumer surpluses, thousands of euro

	first best		oligopoly					
						privatization of EDF		
node	constrained	unconstrained	constrained	unconstrained	relaxed	complete		partial
						1^{st}	2^{nd}	
$n1$, Germany	3959	3960	3480	3480	3480	3480	3480	3480
$n2$, France	4410	3686	1232	3240	1401	2927	2313	4410
$n3$, Belgium	245	205	120	180	104	144	134	88
$n6$, Belgium	137	137	87	120	77	94	90	88
$n4$, Netherlands	276	410	276	360	268	276	276	276
$n5$, Netherlands	205	410	272	360	276	249	261	267
$n7$, Netherlands	148	205	147	180	149	151	150	148
Total	9 379	9 011	5 614	7 920	5 754	7 321	6 703	8 757

Table A.5: Hourly welfare, thousands of euro

	first best		oligopoly					
						privatization of EDF		
node	constrained	unconstrained	constrained	unconstrained	relaxed	complete		partial
						1^{st}	2^{nd}	
$n1$, Germany	4255	4267	4171	3962	4137	4210	4250	4283
$n2$, France	4519	4354	3613	4530	3766	4165	4138	4506
$n3$, Belgium	254	245	195	196	208	234	202	216
$n6$, Belgium	142	153	116	128	111	130	118	144
$n4$, Netherlands	396	549	409	452	240	399	389	361
$n5$, Netherlands	384	550	420	540	458	410	415	418
$n7$, Netherlands	199	275	110	240	200	156	156	110
Total	10 152	10 393	9 035	10 048	9 121	9 704	9 568	10 039

A.3 Firms' profits

Table A.6: Hourly profits, thousands of euro

	EBEL	EDF	EON	RWE	j1
perfect competition, constrained lines					
Germany			98.0	94.0	112.0
France		140.0			
Belgium	36.0				
Netherlands	45.7		23.0		74.7
oligopoly, constrained lines					
Germany			194.0	220.0	392.0
France		2054.1			
Belgium	295.9				
Netherlands	38.6		23.0		47.2
oligopoly, unconstrained lines					
Germany			226.0	254.0	392.0
France		1080.0			
Belgium	144.0				
Netherlands	8.0		8.0		16.0
oligopoly, relaxed lines					
Germany			226.0	170.0	392.0
France		1972.3			
Belgium	311.4				
Netherlands	46.1		24.5		55.0
division of EDF with complete privatization - 1^{st} equilibrium					
Germany			190.0	185.0	392.0
France		(371.8+370.9+518.6)[23]			
Belgium	193.7				
Netherlands	38.7		23.0		56.4
division of EDF with complete privatization - 2^{nd} equilibrium					
Germany			226.0	165.0	392.0

[23]Hourly profits of two non-nuclear and one nuclear company correspondingly.

	EBEL	EDF	EON	RWE	j1
France		(474.3+474.3+675.6)[24]			
Belgium	266.4				
Netherlands	39.6		23.0		51.7
	division of EDF with partial privatization				
Germany			190.0	150.0	392.0
France		(70.0+70.0)[25]			
Belgium	149.4				
Netherlands	37.1		23.0		49.1

A.4 Comparison with the results of Gabriel and Leuthold (2010)

Table A.7: Nodal prices, €/MWh. Columns with first best results and cases (a)-(d) taken from Gabriel and Leuthold (2010), table 18. Last column refers to the equilibrium in the market when all four companies EBEL, EDF, EON, RWE - act strategically, i.e. to the solution of the corresponding EPEC.

node	first best	only one strategic firm				oligopoly
		(a)	(b)	(c)	(d)	
		EBEL	EDF	EON	RWE	
$n1$, Germany	22.0	22.0	22.0	22.0	29.4	30.0
$n2$, France	10.0	10.0	41.7	10.0	10.0	76.0
$n3$, Belgium	10.0	58.4	22.0	10.0	10.0	52.0
$n6$, Belgium	22.0	52.1	30.0	22.0	22.0	48.0
$n4$, Netherlands	45.0	45.0	45.0	45.0	45.0	45.0
$n5$, Netherlands	59.3	45.0	57.2	59.3	58.9	45.6
$n7$, Netherlands	41.3	38.2	41.2	41.3	44.8	41.4

[24] Hourly profits of two non-nuclear and one nuclear company correspondingly.

[25] Hourly profits of two non-nuclear companies.

A.5 Robustness check for lower marginal cost with gas generation units

Table A.8: Nodal prices, €/MWh, total hourly welfare and total hourly consumer surplus (CS), thousands of euro, calculated under assumption of marginal cost for gas generation units equal to 40 €/MWh

	oligopoly			
	privatization of EDF			
	constrained	relaxed	complete	partial
$n1$, Germany	30.0	30.0	30.0	28.5
$n2$, France	76.0	72.9	49.7	10.8
$n3$, Belgium	49.8	56.7	43.0	56.9
$n6$, Belgium	41.1	53.5	42.3	42.5
$n4$, Netherlands	40.0	45.6	40.0	40.0
$n5$, Netherlands	40.9	43.7	40.7	40.6
$n7$, Netherlands	37.8	40.0	37.0	36.8
welfare	9 054	9 076	9 576	10 010
CS	5 692	5 711	6 791	8 886

Chapter 2

Anticompetitive effects of RES infeed in a transmission-constrained network

Abstract

In the process of the de-carbonization of the power industry many countries are adding substantial capacities of wind and solar based power generation to their portfolio. While ownership of conventional capacities is typically concentrated, renewable energy is often provided by small, independent producers. Hence, one might expect competitive pressure to increase as renewable energy production is ramped up. In this paper we show that with insufficient transmission capacities, an increase of renewable infeed in the surplus region might lead to a decline in total generation and consumer surplus in the market. The reason for this somewhat counter-intuitive effect is a switch from an equilibrium in which the market is fully integrated to an equilibrium in which transmission constraint is binding. The resulting fragmentation of the market allows the dominant conventional producers to exploit their local market power more aggressively.

Keywords: renewable energy, electricity transmission, capacity constraints, market power, Germany

2.1 Introduction

In the process of the de-carbonization of the electric power industry many countries are adding substantial capacities of such intermittent renewable energy sources (RES) as wind and solar based power to their portfolio. At the same time, little conventional capacity is being retired, as it is needed for those times when RES generation is low. While ownership of conventional capacities is highly concentrated in many regions of Europe, the potential for the abuse of market power should decline as RES generation increases. First, in many countries wind and solar energy is provided by new, independent producers. Hence, for an incumbent the infra-marginal gains from increasing the price by withholding supply are diminished. Second, given their low variable cost, RES production is first in the merit order and the incumbent will dispatch conventional plants at the margin, which have lower cost, compared to dispatch without RES. Then at a given price, the marginal profit of the incumbent with market power would increase, making it more costly to withhold supply. Both effects suggest that competitive pressure in the electric power industry should increase as RES production is ramped up.

However, the ideal locations for wind and solar power generation are often distant from where demand resides. RES energy has to be transported over long distances to the customers and current transmission systems are poorly designed for this new task. This is particularly true for wind power produced in coastal areas. For example Germany rapidly increased its wind power capacity but failed to keep up with the complementary network expansion. As a result, the transmission system became increasingly congested. The volume of curtailed energy has grown dramatically since 2010 (Bundesnetzagentur and Bundeskartellamt, 2019). In 2015-2017 each year from 4.4 to 5.1% of wind generation could not be injected because the transmission system was insufficient to transport the energy to the customers.[26] With insufficient transmission capacities, the intuition developed in the previous paragraph can be misleading. The benefits of independent production for competition may get lost and even turn into the opposite.

In this paper we show that with sufficiently limited transmission capacities an increase of RES production may lead to a decline in competition, hence consumer surplus and perhaps even welfare. The narrative is as follows: consider two incumbents ”North” and ”South”, both dominating their respective area, and assume that the transmission capacity between

[26]See Bundesnetzagentur and Bundeskartellamt (2017a), page 101, Bundesnetzagentur and Bundeskartellamt (2017b), page 110 and Bundesnetzagentur and Bundeskartellamt (2019), page 141 for curtailed wind energy, and Fraunhofer ISE (2018) for total annual wind generation.

the two regions is limited. Suppose we start from an equilibrium in which the transmission constraint is not binding. As we have the same price in both regions and both companies compete for the whole market, we will refer to this situation as an *integrated market*. Now let RES production gradually increase, but only in the north. With an uncongested transmission line, the duopolists will partially offset the increase but total generation will increase in equilibrium and the price and profits will decline. At some point however, the producer in the south may find it more profitable to focus entirely on her local market while accommodating maximal imports. By cutting back supply she allows the transmission line to congest, so that she becomes a monopolist for the residual local demand. The counter-intuitive effect of RES infeed on consumer surplus is a result of a switch from an equilibrium without binding transmission constraints, the *integrated market*, to an equilibrium with binding transmission constraint, to which we will refer as a *fragmented market*. The resulting fragmentation of the market allows the dominant player to exploit her local market power.

We model a electric power market in which generators recognize that they compete not only with other producers at their own node, but, subject to transmission constraints, also with producers in the rest of the network. Cardell et al. (1997) have been the first to demonstrate strategic congestion as a possible feature of an equilibrium in such a market. They develop a fictitious network with loop flows, where players may find it profitable to either increase or restrict output, congesting the line either from or into her area of dominance. Borenstein et al. (2000) then laid the analytical foundation for the study of market equilibria in a setting of spatial competition. Their focus was on the central role of transmission capacity. For a simple two nodes / one line network Borenstein et al. (2000) describe and relate the possible pure and mixed strategy Nash equilibria to the capacity of the transmission line. Their analysis reveals two important thresholds. The first is the maximum line capacity that allows for an equilibrium with strategic congestion on the line. The second is the minimum line capacity for which an unconstrained Cournot equilibrium is feasible. Depending on the asymmetries between the two nodes, for the capacities between the two thresholds either two or no pure strategy Nash equilibria will exist.

Among others Neuhoff et al. (2005), Ehrenmann and Neuhoff (2009), Gabriel and Leuthold (2010), and Spiridonova (2016) look at market power in more realistic, multi-node and multi-line networks. The application of this approach to a more complex networks, however, proved to be cumbersome, because the resulting mathematical model is in general non-convex and difficult to solve.[27] In their paper Neuhoff et al. (2005) demonstrate that the analysis is greatly

[27] For one strategic generator, the problem of profit maximization subject to first order necessary optimality conditions from the system operator's problem will be a mathematical program with equilibrium constraints (MPEC).

simplified by assuming that generators are myopic, ignoring their influence on transmission constraints. However the resulting equilibrium price will be lower, hence, the potential for the abuse of market power is underestimated.

In this paper we stick to the simple network model of Borenstein et al. (2000) and assume that generators understand how to manipulate congestion for their advantage. In the next section we describe methodology and use graphical tools borrowed from Borenstein et al. (2000) to illustrate how the nature of the spatial equilibrium may change as RES infeed increases. Then we calibrate the model with German data and find that, given current transmission capacities, higher wind infeed, in fact, increases the potential for the abuse of market power.[28] For a relevant range of parameters, an increase of wind infeed causes the equilibrium to switch, first from a pure strategy unconstrained equilibrium to an equilibrium in mixed strategies, and finally to a pure strategy constrained equilibrium. Over the intermediate range (expected) total output and consumer surplus (occasionally even total welfare) will decline. In the last section we discuss alternative measures to solve the problem such as maintaining enough competitive pressure in the deficit areas and increasing transmission capacity.

2.2 Methodology

2.2.1 Method description

We distinguish only two nodes ”North” and ”South” connected with a transmission line of limited capacity k. There is demand in both nodes, and one strategic firm (N and S respectively) with market power in each node. The line is operated by a system operator, who collects quantity bids and clears the markets by setting nodal prices in order to maximize social welfare. While this institutional setting is atypical for European countries, it yields a clear benchmark against which we can discuss alternative institutional arrangements. It also reflects market coupling between different price-zones in Europe reasonably well.

We adopt the approach of Borenstein et al. (2000), who focused on the influence of transmission capacity on the pure strategy equilibrium in spatial competition with players that know

Finding a market equilibrium with several strategic generators will require solving a system of MPECs, or an equilibrium problem with equilibrium constraints (EPEC). A number of papers, for example, Fortuny-Amat and McCarl (1981) and Gabriel and Leuthold (2010) address the challenges of finding a solution for an MPEC.

[28] For the German transmission grid the relevant RES infeed is from wind turbines which are concentrated in the north. Generation from photovoltaic is more of a challenge for distribution networks.

how to influence line flow and congestion to their advantage. In their paper characteristics of the residual demand, that each strategic player faces, were constant. In contrast, we consider the effect fluctuating RES supply has on the equilibrium: the larger the competitive generation in a node, the less residual demand is left for the strategic player in that node, the more the nodal residual demand curve is shifted to the left. With a linear demand assumption, this translates into demand intercept decreasing by demand slope times RES infeed. In our calibration, wind infeed takes place only in the node north. Although this assumption is an obvious simplification, it captures problems arising due to the region with high RES potential being located away from the load center.

Given that strategic conventional players know how to manipulate the flow in the network to their advantage, for any level of opponent's output a strategic player has three options. She can decide to generate enough power so that the transmission constraint is not binding, or it is binding in either export or import direction. That is, the profit function of each strategic conventional player is piece-wise. It consists of the three sections.

In the case of transmission constraint binding in the direction from north to south, the corresponding profits of strategic players S and N are:

$$\pi_S^{MI} = p_S(g_S + k) \cdot g_S - c_S \cdot g_S^3/3 \tag{2.1a}$$
$$\pi_N^{ME} = p_N(g_N + w - k) \cdot g_N - c_N \cdot g_N^3/3 \tag{2.1b}$$

In the case of non-binding transmission constraint, the corresponding profits of strategic players S and N are:

$$\pi_S^{int} = p_{int}(g_N + g_S + w) \cdot g_S - c_S \cdot g_S^3/3 \tag{2.2a}$$
$$\pi_N^{int} = p_{int}(g_N + g_S + w) \cdot g_N - c_N \cdot g_N^3/3 \tag{2.2b}$$

In the case of transmission constraint binding in the direction from south to north, the corresponding profits of strategic players S and N are:

$$\pi_S^{ME} = p_S(g_S - k) \cdot g_S - c_S \cdot g_S^3/3 \tag{2.3a}$$
$$\pi_N^{MI} = p_N(g_N + w + k) \cdot g_N - c_N \cdot g_N^3/3 \tag{2.3b}$$

Where $p(q) = a - b \cdot q$ denotes the inverse demand[29], g the power generated, c the marginal cost coefficient (see section 2.3 for more details), and w wind production. Indices S and

[29] I.e., price depending on consumption. Consumption in each market consists of local generation plus net imports.

N refer to strategic players. Index MI refers to a monopolist facing residual demand constrained by import into her node, ME - to a monopolist facing residual demand expanded by exports out of her node. Index int refers to the integrated market.

2.2.2 Equilibria

Borenstein et al. (2000) have demonstrated that in this set-up two pure strategy equilibria are possible: an equilibrium without binding transmission constraint, and an equilibrium with binding transmission constraint.

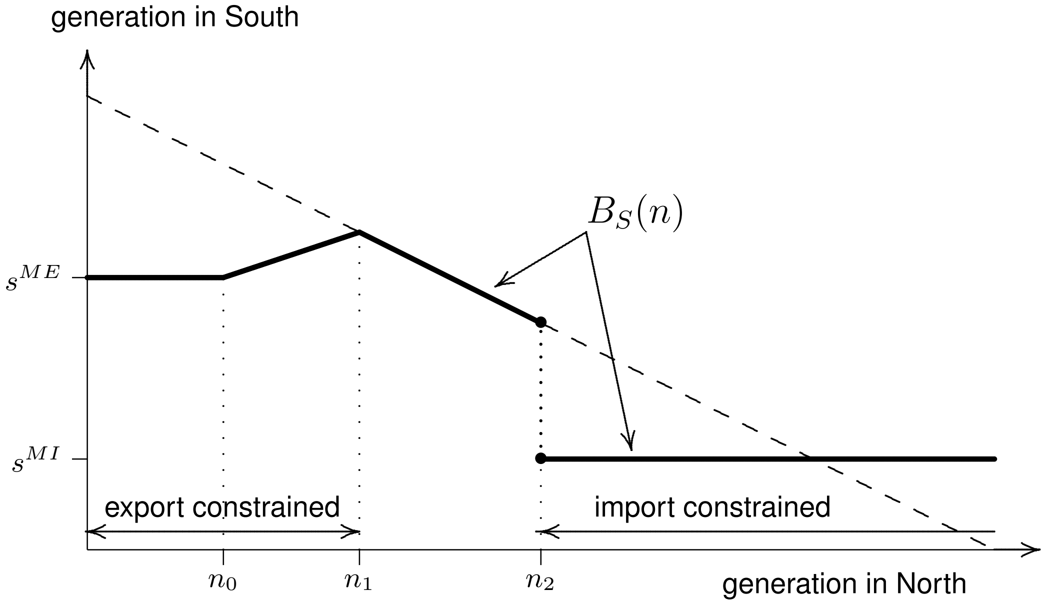
Without binding transmission constraint the markets are integrated and the pure strategy equilibrium is a standard Cournot case. The equilibrium outputs g_N^* and g_S^* can be obtained as the positive root of the polynomials from the first order conditions to maximization of equations (2.2a) and (2.2b).

An equilibrium with binding transmission constraint involves one strategic player exporting as much as possible (k), while another accepts imports in her market and behaves as a monopolist on the remaining demand. Hence Borenstein et al. (2000) call this type of equilibria "passive-aggressive". In our calibration fragmented market involves line congestion from north to south: as much as possible is exported from the node with cheap RES power to the node with large demand. The equilibrium outputs g_N^{ME} and g_S^{MI} can be obtained from the first order conditions to maximization of equations (2.1a) and (2.1b).

2.2.3 Graphical illustration

In figure 2.1 we plot the southern firm's best response B_S to any quantity n generated in the north. The dashed line is the (usual) unconstrained Cournot best response function. For a transmission constraint which is sufficiently tight, this function has to be modified. For the best response B_S we can distinguish four ranges. First, consider the response to very low generation in the North. As line capacity is small compared to demand in the North, S produces the monopoly quantity for the South and exports as much as possible to the North (S^{ME}, see equation 2.3a). For $n \in [0, n_0)$ the price in the North is higher than in the South and the line is congested towards the North. A small increase of n is fully absorbed in the north, where it reduces the price. As it does not change the optimal response of S, prices in the South are constant in this range. At n_0 however, any further increase of n

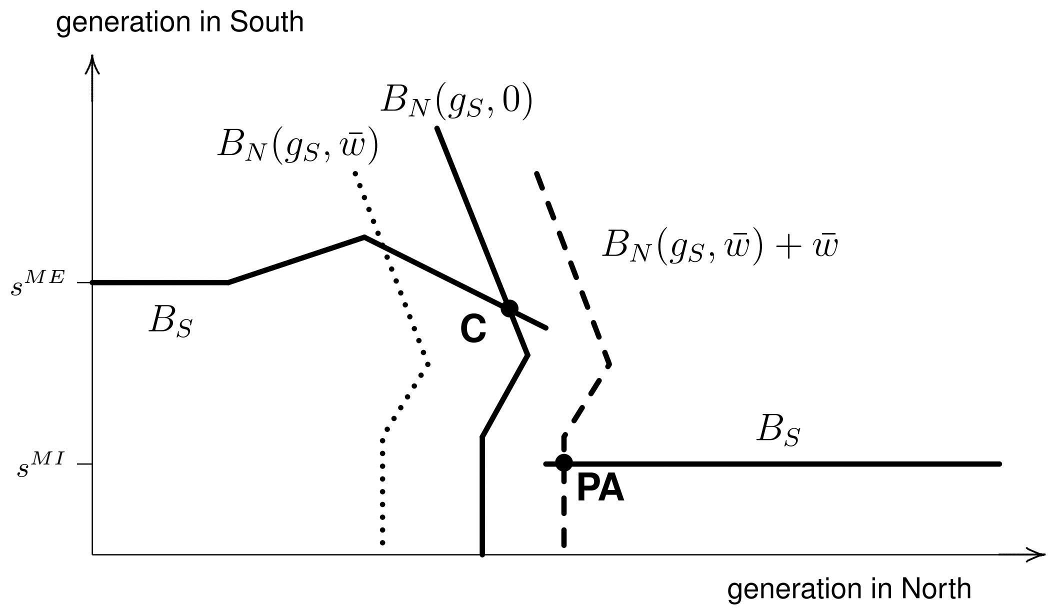
Figure 2.1: A transmission constrained reaction function



would make the line uncongested. As S is well below her unconstrained best response, she increases the output to keep the line congested towards the North, preventing competitor from entering her market. For $n \in [n_0, n_1]$ prices in both regions are decreasing in n. When hitting the unconstrained best response at n_1 the regime changes again and the transmission constraint stops to bind. For $n \in [n_1, n_2]$ we have the textbook case of a unified market with $p_N = p_S$ and S responding to an increase of output in the North by reducing her own output (strategic substitutes). Total output increases in n and the uniform price as well as S's profit declines. However, contrary to the textbook case the profit will not decline towards zero. Given a transmission capacity which is small in relation to demand in the South, S can always choose to accommodate the maximal import k and become a monopolist for the residual demand in the South, producing S^{MI} (see equation 2.1a). Suppose it is at output n_2 where the profit from competing in the whole market becomes equal to the profit of such passive monopolist. Here a small increase of n triggers a drop in generation in the South and the line becomes congested towards the South. This discontinuous drop of generation in the South in response to a small increase of generation in the North results in a decrease of total power generation and welfare. For $n > n_2$, any further increase of generation in the North will not change the price in the South.

In most cases we will have substantial conventional production also in those regions with

Figure 2.2: A change of equilibrium



temporarily high wind infeed. To account for this feature, consider a strategic firm N which generates g_N from the conventional generation capacities in the North. Total generation in the North is then $g_N + w$, with w denoting the infeed from wind turbines (and other fringe generators). The best response of the northern incumbent, $B_N(g_S, w)$, depends on generation in the south g_S and on wind infeed in the North w. Recall that B_S has been defined as a best response to the total generation in the North, irrespective of its source. Hence, it does not change with increased wind infeed, as seen in figure 2.2. In this figure we start from a situation in which there is no wind infeed ($w = 0$) and assume that we would have an equilibrium without congestion. It is indicated by the two solidly drawn best response functions B_S and $B_N(g_S, 0)$ with the standard Cournot-equilibrium marked as C. Now suppose that wind infeed increases to $\bar{w}$. Although N will reduce its output in response to wind generation in its own market (as indicated by the dotted function $B_N(g_S, \bar{w})$), total generation in the North, the dashed line labelled $B_N(g_S, \bar{w}) + \bar{w}$ will increase. As a result the equilibrium switches from one with non-binding transmission constraint to the one with strategic congestion on the line (”passive-aggressive” equilibrium), marked as PA in figure 2.2, with lower total power generation.

Obviously, this is only one of several possibilities. Depending on the demand and the generation cost in the two regions and on the transmission capacity there also may be two equilibria or no equilibrium in pure strategies (Borenstein et al. (2000), theorem 5). To address the practical relevance of these theoretical possibilities we have to calibrate the model with reasonable parameters which leads us to the next section.

2.3 Calibration

In the following we calibrate the two node model assuming linear demand functions and quadratic marginal cost functions using data from the German/Austrian electric power market. In principle, this region is a good example for the issues we want to address. It has large wind infeed in the north-east, substantial power consumption in the south-west and a transmission systems which struggles to cope with the new challenge. Some other features, however, do not correspond well with our simple model. First, the market is operated as one price-zone with redispatch rather than as a two node system. Second, the conventional capacities are distributed not among two, but among several large firms. We will address the relevance of these features in the concluding section.[30]

2.3.1 Network and transmission capacity

Even in times of low wind infeed and slack transmission capacity, the dominant direction of power flows in the German grid is from north to south. Large low cost generation capacities are located in the north while important centres of consumption are in the south and south-west. As most nuclear power stations are located in the south, this imbalance is set to increase with the nuclear phase out.[31] When wind infeed is strong, transmission constraints tend to bind in central Germany from the state Lower Saxony into the states of North Rhine-Westphalia and Saxony as well as from Saxony-Anhalt into Bavaria. If combined with strong load, a broader corridor of lines become congested, but the pattern is the same: lines towards the south or south-west are affected most. Congestion is quite common in Germany. In

[30]We calibrate the model on the data referring to the time when Germany and Austria were in one price zone, prior to the zone split along the border on October 1^{st} 2018. We have performed a robustness check on the Germany only data. This calibration produces slightly different numerical results, but our key findings - the non-monotonic dependence of consumption, prices and consumer surpluses on renewable infeed - remain. Therefore we proceed with our German/Austrian calibration.

[31]See Egerer et al. (2016) and Egerer et al. (2014), page 29 for nuclear power plant locations.

2014-2016 redispatch measures were taken on more than 300 days each year.[32] Feed-in management, or curtailment of RES infeed in cases when network capacities are not sufficient to transport the total amount of electricity generated, increased dramatically since 2010 (Bundesnetzagentur and Bundeskartellamt, 2019). The high incidence of congestion in Germany has led the Agency for the Cooperation of Energy Regulators (ACER) to pressure for the splitting up of the price zone. Such a split would help to alleviate loop flows which have to be accommodated by neighbouring states, in particular Poland and Czech Republic (ACER, 2015b; ENTSO-E, 2012). Politicians reluctantly bowed to the pressure by separating Austria from Germany — a move which will become effective in September 2018. But at the time of writing, there are little signs that German politics is prepared to allow for the more relevant splitting of the German market.

For the calibration we aggregate in the node North the federal states of Berlin, Brandenburg, Bremen, Hamburg, Lower Saxony, Mecklenburg-Vorpommern, Saxony, Saxony-Anhalt and Schleswig-Holstein. The node South includes the federal states Baden-Wuerttemberg, Bavaria, Hesse, North Rhine-Westphalia, Rhineland-Palatinate, Saarland and Thuringia, as well as Austria and Luxembourg.[33]

Unfortunately, the line capacities in a meshed network do not translate directly into available transmission capacities. Analysing flow data from all German TSOs for the European Commission, Thema (2013) conclude that "there is large uncertainty around the actual internal transmission capacities within Germany". To account for this uncertainty Thema (2013) consider scenarios of 7 GW, 10 GW, 13 GW and 16 GW of available transmission capacities between the north and the south of Germany (Thema (2013), pages 22 and 37). As our definitions of nodes is very similar, we consider the same range of capacities. Germany makes efforts to enhance its north-south transmission capacities by another 8 GW by 2025, but the projects are behind schedule and wind capacities are also scheduled to increase in the same time period up to 60.6 GW in the north and up to 13 GW in the south of Germany (Fraunholz and Hladik, 2018).

[32]See Bundesnetzagentur and Bundeskartellamt (2016), page 100; Bundesnetzagentur and Bundeskartellamt (2017a), page 94; Bundesnetzagentur and Bundeskartellamt (2017b), page 102; Forschungsstelle für Energiewirtschaft (2015), chapters 2 and 3. Bundesnetzagentur and Bundeskartellamt (2017a), Section C.5.1 attributes high redispatch volume in 2015 not only to the delays in line expansion, but also to high level of installed wind capacity and relatively windy weather.

[33]A similar division of federal states is used in Thema (2013). Egerer et al. (2016) use a slightly different division assigning Nordrhein-Westfalen and Thuringia to the north.

Table 2.1: Intercept and slope parameters of inverse demand

	mean scenario			peak scenario		
	integrated	North	South	integrated	North	South
intercept (a)	164.00			158.58		
slope coefficient (b)	1.98187	7.92749	2.6425	1.22645	4.9058	1.63527

Table 2.2: Marginal costs (mc) and installed generation capacities ($\overline{gen}$)

	waste	biomass & biogas	hydro	nuclear	lignite	hard coal	gas	other fossil	oil
mc, [€/MWh]	0	0	0	10	20	40	80	80	100
$\overline{gen}$, [GW]									
North	0.6	0.6	1.5	4.1	10.4	7.4	6.9	0.7	1.7
South	1.0	0.6	11.4	6.7	10.4	19.9	15.6	1.7	2.0

2.3.2 Demand and cost

We assume a linear inverse demand function and consider two scenarios: mean and peak. The demand function for each scenario is estimated as passing through a corresponding reference point, determined for 2014 based on the load data from ENTSO-E and the price data from EEX: mean load 66.2 GW and price 32.8 €/MWh; peak load 86.2 GW and price 52.9 €/MWh.[34] Following Leuthold et al. (2005) and Leuthold et al. (2008) we assume demand elasticity of -0.25 at the mean reference point. For the peak scenario we assume a higher demand elasticity of -0.5. Next we decompose total demand into two nodal demands in proportion to the GDP of the respective region. The smaller Northern node accounts for 25% of total GDP, while the Southern node accounts for the remaining 75%.[35] The resulting parameters are given in table 2.1.

To obtain marginal costs, we construct a merit order curve for each node combining the information on conventional installed capacities in Germany, Austria and Luxembourg obtained via Open Power System Data (2016) and marginal costs estimations based on Egerer et al.

[34] For the peak demand scenario hourly loads in 2014 in the price zone of Germany, Austria and Luxembourg were sorted from highest to lowest. The peak reference point values refer to the mean load and price in the top 5% of hours with highest load.

[35] Recall that we include Austria and Luxembourg. Data from Statistisches Bundesamt (2016) and Eurostat (2016).

(2014) (see table 2.2). For both nodes we obtain a very good fit for marginal cost with a simple polynomial having only a quadratic term ($mc(g) = c \cdot g^2$). The coefficients for the quadratic term are $c_N =$ 0.0904321 and $c_S =$ 0.0209779 for North and South, respectively.

2.4 Results

2.4.1 Equilibria

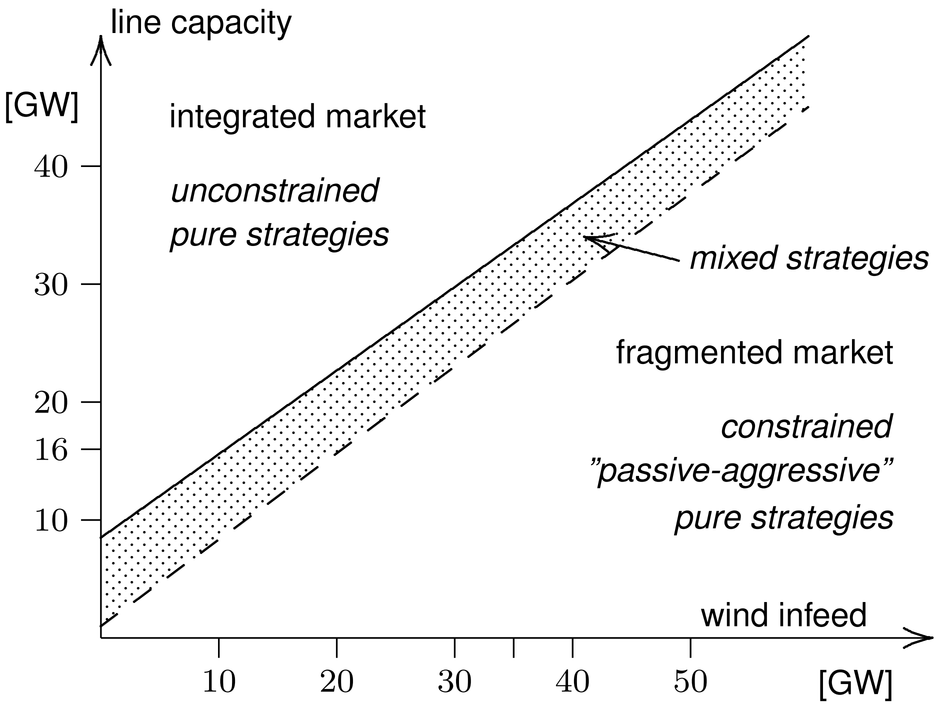
We first look at how an increase of wind infeed impacts on the type of the equilibrium. Figure 2.3 relates the two parameters, wind infeed and transmission capacity, to the type of equilibrium. It has been drawn for the peak load scenario, but the results are very similar in the mean load scenario. In the blank area towards the northwest, we have combinations of low wind infeed and high capacity. In this area we find unconstrained Cournot equilibria in pure strategies, i.e. an integrated market with the same price in both regions. Towards the south-east we have combinations of high wind infeed and low capacity. Here we find transmission constrained pure strategy equilibria for which the market is fragmented and prices in the node North are lower than in the node South. Finally, the dashed area stretching from south-west towards north-east represents those combinations of parameters for which only equilibria in mixed strategies exist. The solidly drawn upper limit is the minimum capacity to support an integrated market. The dashed line gives the maximum capacity for which a passive-aggressive equilibrium with a fragmented market can be supported.[36]

If we assume a transmission capacity of 16 GW, for wind infeed ranging from zero to 35 GW[37] and increase wind infeed gradually, we hit the regime switch from an integrated market to the intermediate range at approximately 10.5 GW. When wind generation reaches approximately 20.5 GW a unique passive-aggressive equilibrium emerges. Given the rapid growth of installed capacity of wind-turbines in Germany, the likelihood of wind infeed to be in the critical range from 10.5 to 20.5 GW has increased from 11.1% in the years 2013/14 up to 26.2% in the years 2015/16 (see appendix B.1 for the corresponding distribution functions). For the mean load scenario the two threshold values are slightly higher, 11.9 GW, and 21.6 GW respectively.

[36]One might note that for any level of wind infeed the optimal unconstrained flow of power is in the dashed area, between the minimum capacity for an integrated and the maximal capacity for a fragmented market.

[37]Fraunhofer ISE (2016) reports record of hourly wind production of 35.6 GW on 21 December 2015.

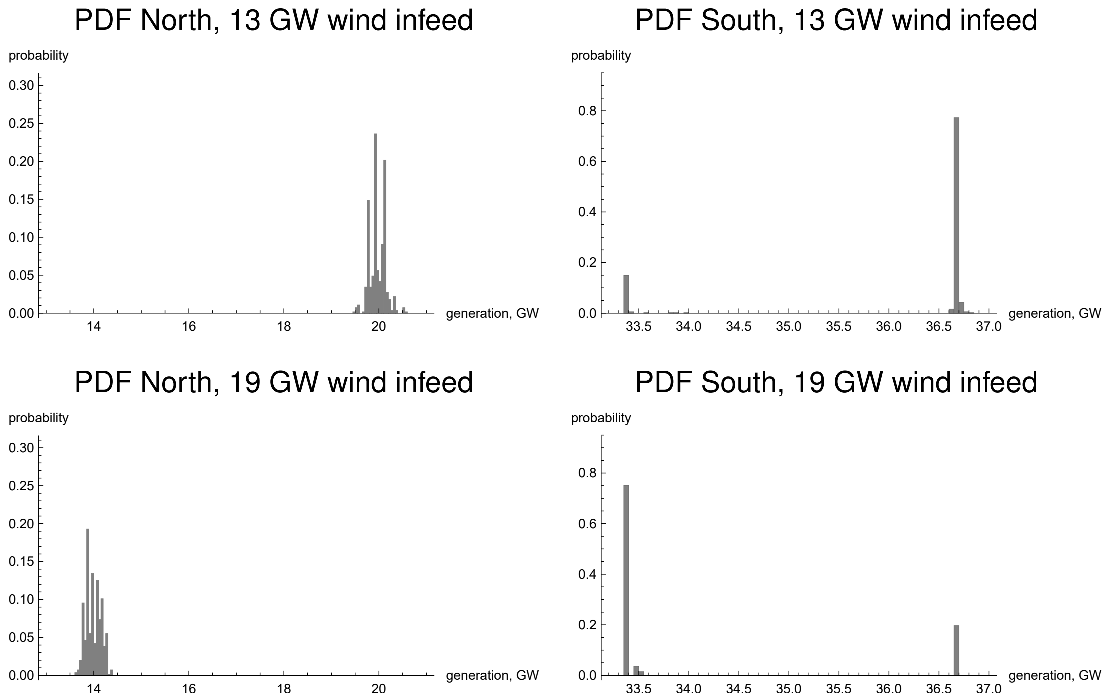
Figure 2.3: Type of equlibrium depending on transmission capacity and wind infeed in the network



In the intermediate range, there exist no equilibrium in pure strategies. We approximate the equilibrium in mixed strategies using a recursive numerical method adopted from Borenstein et al. (1998) (see appendix B.2 for a brief description). In a nutshell: we represent a mixed strategy by a set of fifty pure strategies, each played with probability 0.02. Given the mixed strategy of her opponent, in each round a player adds a new pure best response to this set and deletes the pure strategy for which expected profit is lowest. The process terminates when the differences between the expected profits for the pure strategies within each set are sufficiently small. In our case this process converged fast and reliably, independently of the starting values.

Our numerical approximation of the mixed strategy equilibrium reveals a clear pattern (for an illustration see figure 2.4). The player in the North randomizes in a small interval which

Figure 2.4: Probability density functions (PDFs) in mixed strategy equilibria



includes the unconstrained pure strategy best response. As wind infeed is increased, the support of mixed equilibrium distribution is shifted downward almost one to one. In figure 2.4 we display the equilibrium probability distributions for an infeed of 13 GW in the first row and 19 GW in the second. As infeed is increased by 6 GW conventional generation in the North (left panels) is shifted from values around 20 GW down to values around 14 GW. As a result, expected total generation in the North changes very little. The player in the South (right panels), in contrast, essentially randomizes between her unconstrained pure strategy best response 33.4 GW and the optimal passive output 36.7 GW. Her strategy has two distinct peaks separated by a range played with zero probability. Initially, at an infeed close to the threshold of 10.5 GW the equilibrium strategy puts little probability on the optimal passive output and most of the probability on the unconstrained best response. As wind infeed increases, probability is continuously shifted towards the optimal passive output, which becomes gradually dominant before it receives probability one at 20.5 GW. Hence in terms of expected outcomes (quantities, prices etc.), we can expect a gradual change, instead of a sudden jump as is suggested by figure 2.2.

2.4.2 Consumption, prices and welfare

Now we look at how wind infeed and the resulting regime switches affect quantities, prices, and ultimately welfare in the power market. As before we focus on the case of a transmission capacity of 16 GW and peak demand. Throughout we discuss the results using charts. Tables with numerical values and robustness checks for other transmission capacities can be found in appendix B.3.

Consumption & Prices

Figure 2.5: (Expected) generation and consumption

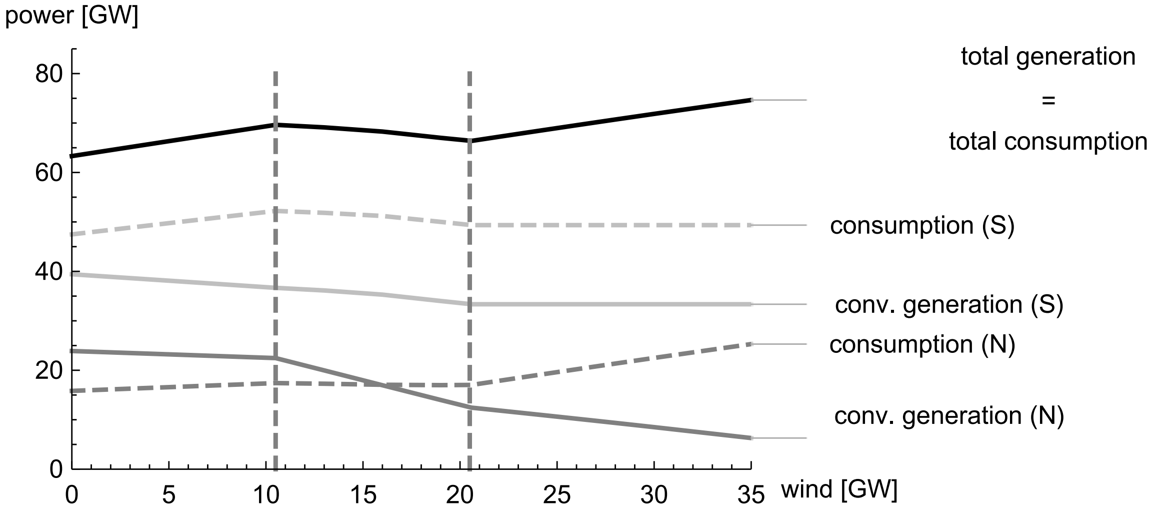


Figure 2.5 illustrates the effect of increasing wind infeed on power consumption and power generation. The upper solid black line shows total generation which is equal to total consumption. The light grey and dark grey dashed lines display how much of total consumption takes place in South and North, respectively. The solid light grey and dark grey lines indicate the power generation from conventionals owned by the two strategic players in South and North, respectively. They do not add up to total generation as wind infeed, which happens only in the North, is excluded.

Consider first the range where the market is integrated (from 0 to 10.5 GW). Here, total generation increases as wind generation is ramped up while conventional generation declines. Since the merit order curves are different in each node, the decline is uneven: conventional generation in the North falls from 23.89 GW to 22.46 GW, in the South — from 39.42 GW to 36.67 GW. In this process costly conventional generation is substituted by cheap RES power.

At the same time consumption, equal total generation, increases, as production from conventional generators decreases less than wind infeed increases. As a result, total generation increases over this range from 63.31 GW to 69.63 GW.

However, the picture changes as we move beyond 10.5 GW into the intermediate range (in between the dashed vertical lines). In this range players select quantities only with probabilities. As we move to the right, quantities which are close to the passive-aggressive equilibrium are played with increasing probabilities in equilibrium. On average an increase in wind infeed is overcompensated by the reduction from conventional production. As a result, expected total consumption declines from its peak of 69.63 GW to 66.39 GW at a wind infeed of 20.5 GW, where the passive-aggressive equilibrium becomes unique.

Once in the region of a fragmented market, the South is effectively insulated against any further increase of wind infeed. Local generation and consumption stay constant at 33.35 GW and 49.35 GW, respectively. Additional wind infeed impacts only on the Northern market where consumption increases from 17.04 GW to 25.3 GW at 35 GW of wind infeed, while conventional generation declines from 12.27 GW to, eventually, zero. It is worth noting that, starting from 10.5 GW wind infeed in an integrated market, it takes an additional 15 GW additional wind power before the same level total consumption is reached again in the fragmented market.

Figure 2.6: (Expected) nodal prices

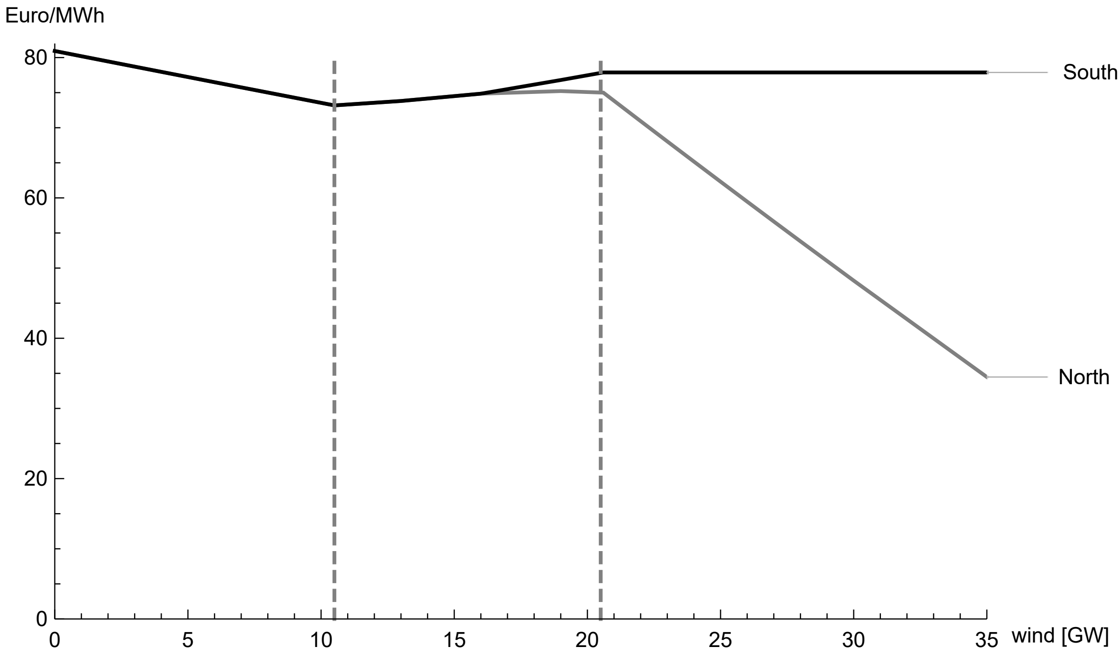


Figure 2.6 displays the corresponding development of nodal prices. In the integrated market,

these are equal in both regions and decrease from 80.93 €/MWh to 73.18 €/MWh as wind infeed climbs from zero to 10.5. In the intermediate range this trend is reversed. Expected prices increase and spread out. When market fragmentation is firmly established at 20.5 GW, the price in the North has increased to 75 €/MWh, while the price in the South reached 77.88 €/MWh. Any further increase of wind generation will sharply depress prices in the North while the southern price will remain constant.

Welfare

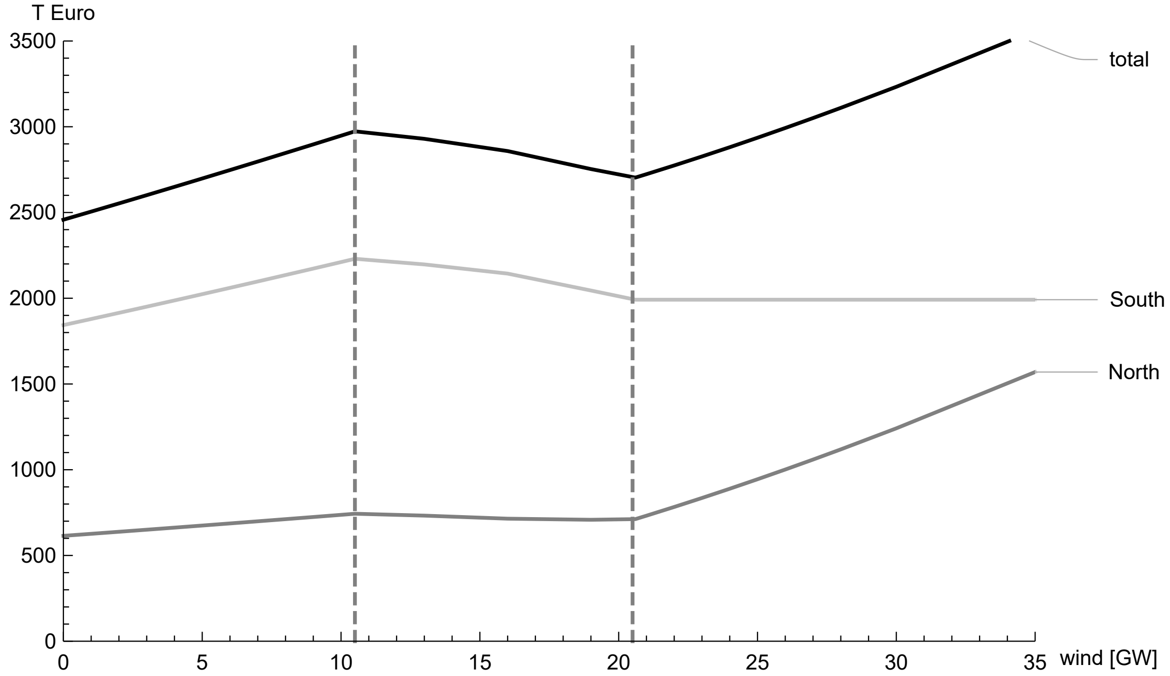
As usual welfare is measured by the difference between total gross consumer surplus and total generation cost. It is, however, instructive to decompose it into the components: net consumer surplus in North and South, profits from conventional generation in North and South, profit from wind infeed, and congestion rent. In principle, welfare should increase as conventional generation is replaced by wind based generation, because fuel cost is saved.[38] However, the impact on market power is non-monotonic and has the potential to offset these gains.

Given the previous results on quantities and prices the effect on net consumer surplus is straightforward (figure 2.7). Initially, wind infeed enhances competition and net consumer surplus in North and South increase. When the regime switches to the intermediate region, however, the trend is reversed and consumer surplus in both regions declines. Once the division of the market is firmly established, consumer surplus remains constant in the South and strongly increases in the North. Total consumer surplus has a local peak at 2.97 million euro per hour when we switch from an integrated market to the intermediate range. Then it drops by app. 10 % down to 2.70 million euro per hour from where it raises again. Most of the decline in the intermediate range takes place in the southern region, while the recovery for very high infeed of wind power is confined to the northern region.

Finally, figure 2.8 presents the generators' profits and the congestion rent. The profits of the generators have been calculated assuming that they sell all their output at their respective node. Whenever nodal prices differ, there is a congestion rent: the gains from buying at the cheap node and selling at the expensive one. Under the standard nodal pricing scheme this rent would be reaped by the transmission system operator to cover the cost of network capacity.

[38] It is worth recalling that we take generation capacities as given. Hence, we ignore capacity cost and consider variable cost only. It is beyond the scope of this paper to account for the full cost of the technologies, which would require to consider reliability issues and the environmental impact as well.

Figure 2.7: (Expected) net consumer surplus

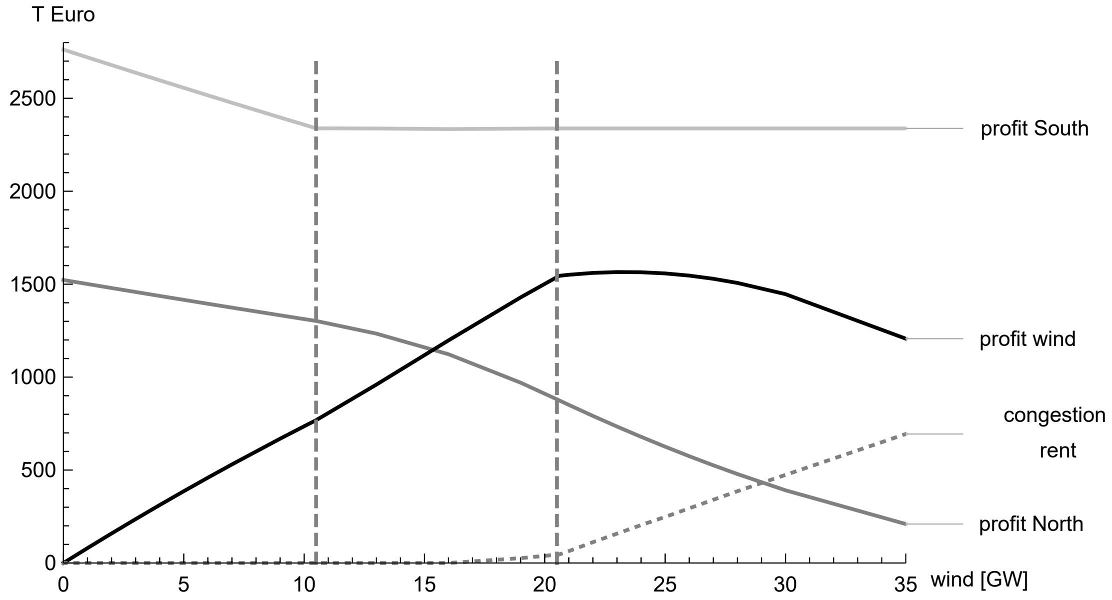


While the market is integrated, increased wind infeed reduces the profits of both conventional generators. Once we move into the intermediate range, where the market starts to disintegrate, the profits of the generator in the South are protected from further decline. It is only the producer in the North which suffers from additional competition of wind power infeed. In contrast, the profit of wind power producers is non-monotonic. In the integrated and intermediate range it increases: the effect from growing sales outweighs the effect from declining price. It reaches its peak of 1.57 million euro per hour at an infeed of 23 GW. As we move further the price effects becomes dominant and the profit declines. It is worth recalling that we ignore any RES energy support schemes (feed-in tariffs or market premiums) in this calculation.

Taken together net consumer surplus, profits and congestion rent yield social welfare. It is not plotted in the figures, but it can be found in the tables of appendix B.3. For the first 10.5 GW of wind power infeed, welfare increases strongly by 0.64 million euro per hour from 6.74 to 7.38 million euro. As we move into the intermediate range the increase flattens off to reach a small local peak with 7.51 at app. 19 GW. Here, the negative impact on wind infeed on competition is slightly stronger the fuel cost savings. After a small drop, welfare increases again in the fragmented market.[39]

[39]Whether the anti competitive effect is even stronger than the cost saving effect depends critically on transmission capacities. For our calibration, it happens for a capacity of 16 and 12 GW, but not for 8 GW.

Figure 2.8: (Expected) profits and congestion rent



2.5 Discussion

In this paper we have explained how an increase of local power production, such as wind, may result in a less competitive overall market when transmission constraints grant strategic players, e.g. conventional producers, regional market power. Using data on German demand, generation capacities, and transmission constraints we calibrated a simple model and demonstrated that this anti-competitive effect of wind infeed is not only a theoretical possibility. It can happen over a wide range of relevant wind infeed[40] and has the potential to substantially affect prices, quantities, and consumer surplus. However, there is a number of important limitations. First, we consider a simple two node system with only one transmission constraint which is operated under nodal pricing. In reality Germany is operated as one price zone with redispatch. Occasionally, it also faces additional transmission constraints within the regions. Second, we ignore imports and exports. Finally, with four large companies operating the conventional generating capacity, the German market is more competitive than we assume in our model.

Accounting for more transmission constraints is likely to increase the scope for the abuse of market power. So does zonal pricing with redispatch. Strategic players will understand that whenever transmission constraints become binding the system operator will eventually

[40] See the distribution functions for wind infeed in years 2013/14 and 2015/16 in the appendix B.1.

depend on generation at a particular location for redispatch. At that stage, however, market power in the deficit region is enhanced as local consumption is already fixed at a price which is too low. Trade with additional regions, in contrast, will tend to weaken the effect, unless transmission constraints bind in a correlated pattern.

The analysis of a market with more than two strategic players is left to future research. Intuitively, the equilibrium of the integrated market will be more competitive with a larger number of players. As this equilibrium brakes down, whenever a firm can obtain a higher profit by reducing its output and creating local market which is protected from imports at the margin, it will depend on the location of the generators whether the anticompetitive effects are enhanced or reduced. If a third firm is located in the North, the problem is aggravated, because the equilibrium profits in the integrated market decline, while the profits of the Southern firm in case of fragmentation remain the same. If a third firm is located in the South, however, it appears likely that the range of wind infeed and transmission capacity, for which we can expect an anti-competitive effect, will be reduced. Any firm withholding supply would share the gains from of an increase of the local price with a local competitor, while facing the cost in terms of lost sales alone. In this sense, our results should be read as a warning: in view of limited transmission constraints it is important to maintain vigorous local competition of conventional producers in potential deficit regions even if an increasing share of power is produced from a competitive fringe of small producers of RES energy in the surplus region.

Appendix B

Anticompetitive effects of RES infeed in a transmission-constrained network

B.1 Distribution of wind generation in Germany

The following figures B.1 and B.2 depict the probability density and cumulative distribution functions of wind generation in Germany in 2013-2016, based on the data from Open Power System Data (2017). We have aggregated years 2013-2014 and 2015-2016 due to their similarities. Higher levels of wind generation became noticeably more likely in 2015-2016 compared to 2013-2014. In the same time period mean wind capacity factors increased from

Figure B.1: Probability density function of wind generation in Germany

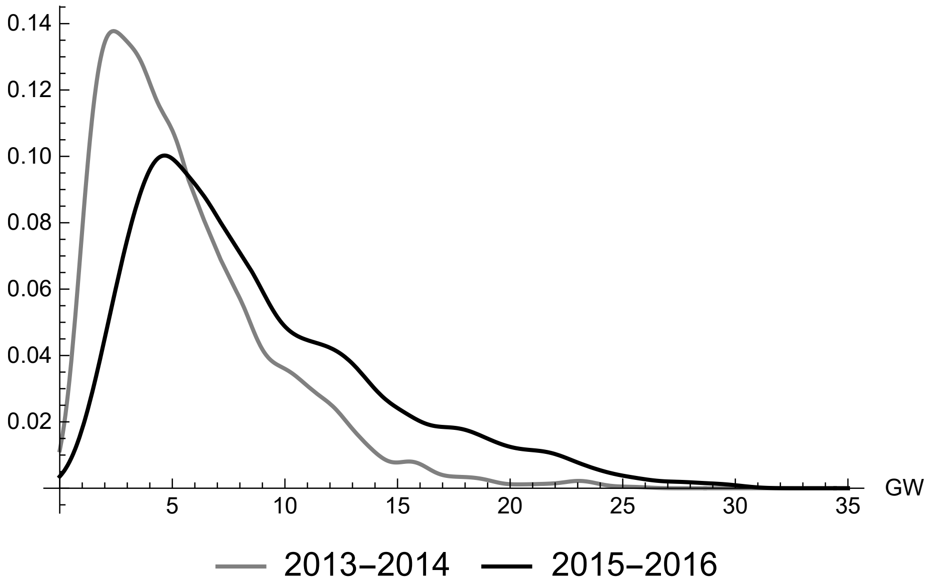
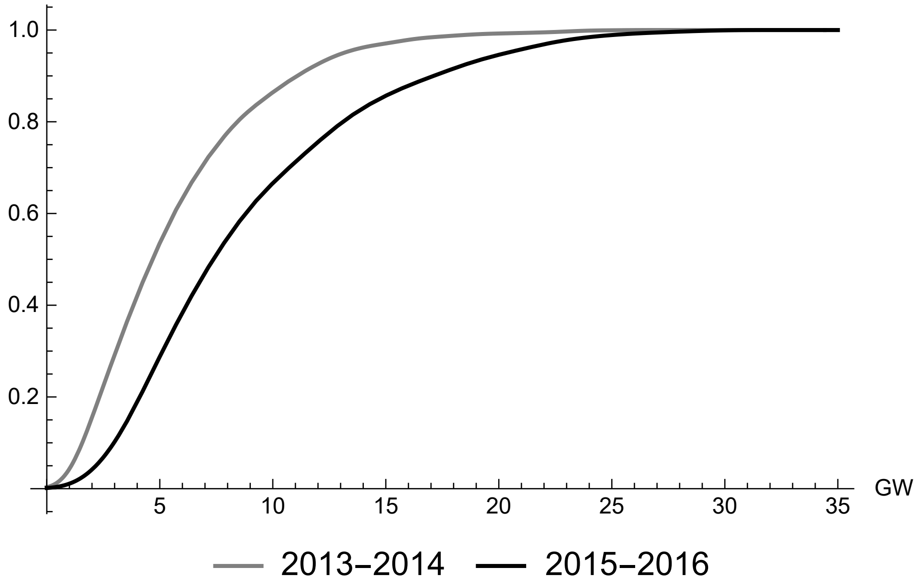


Figure B.2: Cumulative distribution function of wind generation in Germany



17.5% to 20.8%, installed capacities - from 32.1 GW to 42.4 GW.

B.2 Mixed equilibrium approach

In chapter 2 we use the “fictious play” approach to search for the mixed equilibrium, adopted from Borenstein et al. (1998). This approach allows us to construct for each player a mixed strategy, i.e. a probability distribution over a set of pure strategies. Prior to the start of the algorithm, we need to define several things.

First, there is an arbitrary starting point (g_{N0}, g_{S0}). Second, the algorithm is applied for a predefined number of step, or iterations (for each starting point, we set it between 235 and 520). At each iteration, each player adds to her set of pure strategies one more output:

Step 1. Each player determines her pure strategy best response to the output produced by opponent. Since at the starting point player generates only one level of output with certainty, the new optimal generation levels are: $g_{N1} = br_N(1, g_{S0})$ and $g_{S1} = br_S(1, g_{N0})$

Step 2. Each player determines her best response, but now assuming that all of the opponent’s outputs from the previous steps are played with equal probabilities as a mixed strategy. Therefore the new optimal generation levels are the pure strategy best responses to the opponent's mixed strategy: $g_{N2} = br_N((0.5, 0.5), (g_{S0}, g_{S1}))$ and $g_{S2} = br_S((0.5, 0.5), (g_{N0}, g_{N1}))$

The process is continued: each player assumes that her opponent's previous generation levels belong to a mixed strategy and are played with equal probability. Given this assumption, new best responses are determined. If there is no interference, the number of pure strategies in each player's set increases by 1 with every step. This brings us to the third point - we set a cap on the number of pure strategies in each player's mixed strategy. The absence of a cap would substantially increase the computation time and interfere with convergence in cases when a starting point lies far away from the mixed equilibrium. In such a case the starting profit is significantly different from the subsequent ones, resulting in a failure of the algorithm to meet the convergence criteria (more on the convergence below). We set a cap on the number of pure strategies allowed in a mixed strategy at 50.

As the algorithm proceeds, at each iteration each player assumes that her opponent's previous generation levels belong to a mixed strategy and are played with equal probability. Given this assumption, new best responses are determined. Once the cap on the size of the mixed strategy is reached, predefined exclusion criteria removes the pure strategy with the lowest profit from the set. Exclusion criteria calling for removal of the oldest best response was considered but not adopted, as it resulted in a slower convergence.

Finally, we predefine a convergence criteria. In the mixed equilibria each pure strategy in her set brings the player the same profit. Therefore the convergence to mixed equilibrium is declared once the standard deviation of each players' profits from the outputs in her set falls below a predetermined threshold.[41] Otherwise the process fails to converge and terminates when the limit on the number of iterations is reached.

B.3 Equilibrium values in tables

The following tables B.1-B.9 provide numerical description of equilibria for a range of wind infeed values combined with tree levels of transmission capacity between the nodes North and South. The line capacity is equal to 16 GW in tables B.1-B.3, to 12 GW in tables B.4-B.6, and to 8 GW in tables B.7-B.9. Tables B.1, B.4 and B.7 report values of conventional generation, line flow and consumption; tables B.2, B.5 and B.8 - nodal prices, costs of conventional gen-

[41] For each combination of line capacity and RES infeed we considered 11 starting points. Threshold for the profits' standard deviation was set at 0.5 for 8 starting points, and at 0.3 for 3 more starting points.

eration and generators' profits; and tables B.3, B.6 and B.9 - congestion rent, net consumer surplus and welfare. T€ denotes thousand €.

Table B.1: Hourly nodal generation and consumption

	ATC between North and South is equal to 16 GW					
RES	**conventional generation**		**flow**	**consumption**		
North	North	South	N to S	North	South	total
GW	GW	GW	GW	GW	GW	GW
	integrated market					
0	23.89	39.42	8.07	15.83	47.48	63.31
1	23.76	39.16	8.78	15.98	47.94	63.92
2	23.62	38.9	9.49	16.13	48.39	64.52
3	23.49	38.64	10.21	16.28	48.85	65.13
4	23.35	38.38	10.92	16.43	49.3	65.73
4.8	23.25	38.17	11.49	16.55	49.66	66.21
5	23.22	38.12	11.63	16.58	49.75	66.33
6	23.08	37.85	12.35	16.73	50.2	66.94
7	22.94	37.59	13.06	16.88	50.65	67.54
9	22.67	37.07	14.49	17.18	51.55	68.74
10	22.53	36.8	15.2	17.33	52.	69.33
10.5	22.46	36.67	15.55	17.41	52.22	69.63
	intermediate range (expected values)					
13	19.98	36.14	15.63	17.34	51.78	69.12
16	16.98	35.30	15.75	17.22	51.05	68.28
19	13.99	34.01	15.92	17.08	49.93	67.00
	fragmented market					
20.6	12.44	33.35	16	17.04	49.35	66.39
21	12.27	33.35	16	17.27	49.35	66.63
25	10.62	33.35	16	19.62	49.35	68.97
30	8.5	33.35	16	22.5	49.35	71.85
35	6.3	33.35	16	25.3	49.35	74.65

Table B.2: Hourly prices, conventional generation costs and profits

	ATC between North and South is equal to 16 GW						
RES	**price**		**costs**		**profits**		
North	North	South	North	South	wind	North	South
GW	€/MWh	€/MWh	T€	T€	T€	T€	T€
	integrated market						
0	80.93	80.93	411	428	0	1523	2762
1	80.19	80.19	404	420	80	1501	2720
2	79.45	79.45	397	412	159	1479	2679
3	78.7	78.7	391	403	236	1458	2638
4	77.96	77.96	384	395	312	1437	2597
4.8	77.37	77.37	379	389	371	1420	2564
5	77.22	77.22	377	387	386	1416	2556
6	76.49	76.49	371	379	459	1395	2516
7	75.75	75.75	364	371	530	1374	2476
9	74.28	74.28	351	356	669	1333	2397
10	73.55	73.55	345	349	735	1312	2358
10.5	73.18	73.18	342	345	768	1302	2339
	intermediate range (expected values)						
13	73.50	73.91	240	331	956	1228	2338
16	74.08	75.10	148	309	1185	1110	2338
19	74.81	76.93	83	276	1421	964	2338
	fragmented market						
20.6	75.	77.88	58	259	1545	875	2338
21	73.84	77.88	56	259	1551	851	2338
25	62.32	77.88	36	259	1558	626	2338
30	48.21	77.88	18	259	1446	391	2338
35	34.48	77.88	8	259	1207	210	2338

Table B.3: Hourly congestion rent, consumer surplus and welfare

	ATC between North and South is equal to 16 GW						
RES	**cong. rent**	**net CS**			**welfare**		
North		North	South	total	North	South	total
GW	T€	T€	T€	T€	T€	T€	T€
	integrated market						
0	0	614	1843	2458	1484	5258	6742
1	0	626	1879	2505	1503	5303	6807
2	0	638	1915	2553	1522	5348	6870
3	0	650	1951	2601	1541	5392	6933
4	0	662	1987	2649	1560	5435	6995
4.8	0	672	2016	2689	1574	5470	7044
5	0	675	2024	2698	1578	5478	7056
6	0	687	2061	2747	1596	5521	7117
7	0	699	2098	2797	1614	5563	7177
9	0	724	2173	2897	1650	5646	7296
10	0	737	2211	2948	1667	5687	7354
10.5	0	743	2230	2973	1676	5707	7383
	intermediate range (expected values)						
13	7	738	2193	2931	1772	5687	7459
16	16	728	2132	2860	1856	5654	7510
19	34	715	2039	2755	1910	5602	7512
	fragmented market						
20.6	46	712	1991	2703	1932	5575	7507
21	65	732	1991	2723	1952	5575	7527
25	249	944	1991	2936	2131	5575	7707
30	475	1241	1991	3233	2308	5575	7883
35	694	1570	1991	3561	2434	5575	8010

Table B.4: Hourly nodal generation and consumption

	ATC between North and South is equal to 12 GW					
RES	**conventional generation**		**flow**	**consumption**		
North	North	South	N to S	North	South	total
GW	GW	GW	GW	GW	GW	GW
integrated market						
0	23.89	39.42	8.07	15.83	47.48	63.31
1	23.76	39.16	8.78	15.98	47.94	63.92
2	23.62	38.9	9.49	16.13	48.39	64.52
3	23.49	38.64	10.21	16.28	48.85	65.13
4	23.35	38.38	10.92	16.43	49.3	65.73
4.8	23.25	38.17	11.49	16.55	49.66	66.21
	intermediate range (expected values)					
6	22.13	38.00	11.58	16.55	49.58	66.13
10	18.12	36.78	11.73	16.39	48.52	64.91
13	15.13	35.66	11.88	16.24	47.54	63.78
	fragmented market					
15.1	13.04	34.74	12	16.14	46.74	62.89
16	12.68	34.74	12	16.68	46.74	63.42
17	12.27	34.74	12	17.27	46.74	64.02
18	11.86	34.74	12	17.86	46.74	64.61
19	11.45	34.74	12	18.45	46.74	65.2
20	11.04	34.74	12	19.04	46.74	65.78
20.6	10.79	34.74	12	19.39	46.74	66.13
21	10.62	34.74	12	19.62	46.74	66.37
25	8.93	34.74	12	21.93	46.74	68.67
30	6.74	34.74	12	24.74	46.74	71.49
35	4.48	34.74	12	27.48	46.74	74.22

Table B.5: Hourly prices, conventional generation costs and profits

	ATC between North and South is equal to 12 GW						
RES	**price**		**costs**		**profits**		
North	North	South	North	South	wind	North	South
GW	€/MWh	€/MWh	T€	T€	T€	T€	T€
	integrated market						
0	80.93	80.93	411	428	0	1523	2762
1	80.19	80.19	404	420	80	1501	2720
2	79.45	79.45	397	412	159	1479	2679
3	78.7	78.7	391	403	236	1458	2638
4	77.96	77.96	384	395	312	1437	2597
4.8	77.37	77.37	379	389	371	1420	2564
	intermediate range (expected values)						
6	77.38	77.51	327	384	464	1386	2560
10	78.17	79.24	180	350	782	1237	2561
13	78.90	80.84	104	319	1026	1089	2561
	fragmented market						
15.1	79.38	82.14	67	293	1199	969	2561
16	76.75	82.14	61	293	1228	912	2561
17	73.84	82.14	56	293	1255	851	2561
18	70.94	82.14	50	293	1277	791	2561
19	68.05	82.14	45	293	1293	734	2561
20	65.18	82.14	41	293	1304	679	2561
20.6	63.46	82.14	38	293	1307	647	2561
21	62.32	82.14	36	293	1309	626	2561
25	51.01	82.14	21	293	1275	434	2561
30	37.19	82.14	9	293	1116	242	2561
35	23.78	82.14	3	293	832	104	2561

Table B.6: Hourly congestion rent, consumer surplus and welfare

	ATC between North and South is equal to 12 GW						
RES	**cong. rent**	**net CS**			**welfare**		
North		North	South	total	North	South	total
GW	T€	T€	T€	T€	T€	T€	T€
	integrated market						
0	0	614	1843	2458	1484	5258	6742
1	0	626	1879	2505	1503	5303	6807
2	0	638	1915	2553	1522	5348	6870
3	0	650	1951	2601	1541	5392	6933
4	0	662	1987	2649	1560	5435	6995
4.8	0	672	2016	2689	1574	5470	7044
	intermediate range (expected values)						
6	2	672	2010	2682	1626	5468	7094
10	13	659	1926	2586	1761	5417	7178
13	23	647	1849	2496	1824	5371	7195
	fragmented market						
15.1	33	639	1787	2426	1854	5333	7187
16	65	682	1787	2469	1901	5333	7234
17	100	732	1787	2518	1952	5333	7285
18	134	783	1787	2569	2000	5333	7333
19	169	835	1787	2622	2046	5333	7379
20	204	889	1787	2676	2090	5333	7422
20.6	224	922	1787	2709	2115	5333	7448
21	238	944	1787	2731	2131	5333	7464
25	374	1179	1787	2966	2276	5333	7609
30	539	1502	1787	3288	2413	5333	7746
35	700	1852	1787	3639	2503	5333	7836

Table B.7: Hourly nodal generation and consumption

	ATC between North and South is equal to 8 GW					
RES	**conventional generation**		**flow**	**consumption**		
North	North	South	N to S	North	South	total
GW	GW	GW	GW	GW	GW	GW
	intermediate range (expected values)					
0	23.27	39.5	7.57	15.71	47.06	62.77
5	18.26	38.04	7.75	15.51	45.79	61.30
9	14.26	36.31	7.98	15.29	44.28	59.57
	fragmented market					
10	13.49	36.12	8	15.49	44.12	59.61
10.5	13.29	36.12	8	15.79	44.12	59.91
11	13.08	36.12	8	16.08	44.12	60.2
12	12.68	36.12	8	16.68	44.12	60.8
13	12.27	36.12	8	17.27	44.12	61.39
14	11.86	36.12	8	17.86	44.12	61.98
15	11.45	36.12	8	18.45	44.12	62.57
15.1	11.41	36.12	8	18.51	44.12	62.63
16	11.04	36.12	8	19.04	44.12	63.16
17	10.62	36.12	8	19.62	44.12	63.74
18	10.2	36.12	8	20.2	44.12	64.32
19	9.78	36.12	8	20.78	44.12	64.9
20	9.36	36.12	8	21.36	44.12	65.48
20.6	9.1	36.12	8	21.7	44.12	65.82
21	8.93	36.12	8	21.93	44.12	66.05
25	7.19	36.12	8	24.19	44.12	68.31
30	4.94	36.12	8	26.94	44.12	71.06
35	2.6	36.12	8	29.6	44.12	73.72

Table B.8: Hourly prices, conventional generation costs and profits

	ATC between North and South is equal to 8 GW						
RES	**price**		**costs**		**profits**		
North	North	South	North	South	wind	North	South
GW	€/MWh	€/MWh	T€	T€	T€	T€	T€
	intermediate range (expected values)						
0	81.52	81.62	380	431	0	1517	2792
5	82.49	83.70	184	387	412	1323	2792
9	83.59	86.16	87	335	752	1104	2792
	fragmented market						
10	82.61	86.43	74	330	826	1040	2792
10.5	81.14	86.43	71	330	852	1007	2792
11	79.67	86.43	68	330	876	975	2792
12	76.75	86.43	61	330	921	912	2792
13	73.84	86.43	56	330	960	851	2792
14	70.94	86.43	50	330	993	791	2792
15	68.05	86.43	45	330	1021	734	2792
15.1	67.76	86.43	45	330	1023	729	2792
16	65.18	86.43	41	330	1043	679	2792
17	62.32	86.43	36	330	1059	626	2792
18	59.47	86.43	32	330	1070	575	2792
19	56.63	86.43	28	330	1076	526	2792
20	53.81	86.43	25	330	1076	479	2792
20.6	52.13	86.43	23	330	1074	452	2792
21	51.01	86.43	21	330	1071	434	2792
25	39.93	86.43	11	330	998	276	2792
30	26.43	86.43	4	330	793	127	2792
35	13.37	86.43	1	330	468	34	2792

Table B.9: Hourly congestion rent, consumer surplus and welfare

	ATC between North and South is equal to 8 GW						
RES	**cong. rent**	**net CS**			**welfare**		
North		North	South	total	North	South	total
GW	T€	T€	T€	T€	T€	T€	T€
	intermediate range (expected values)						
0	1	605	1811	2417	1505	5221	6726
5	10	590	1716	2307	1686	5158	6844
9	21	573	1604	2177	1763	5084	6847
	fragmented market						
10	31	588	1592	2180	1794	5075	6869
10.5	42	611	1592	2203	1821	5075	6897
11	54	635	1592	2226	1849	5075	6924
12	77	682	1592	2274	1901	5075	6977
13	101	732	1592	2323	1952	5075	7027
14	124	783	1592	2374	2000	5075	7075
15	147	835	1592	2427	2046	5075	7121
15.1	149	841	1592	2432	2050	5075	7126
16	170	889	1592	2481	2090	5075	7165
17	193	944	1592	2536	2131	5075	7207
18	216	1001	1592	2593	2171	5075	7246
19	238	1059	1592	2651	2208	5075	7283
20	261	1119	1592	2710	2243	5075	7319
20.6	274	1155	1592	2747	2263	5075	7339
21	283	1179	1592	2771	2276	5075	7352
25	372	1435	1592	3026	2389	5075	7465
30	480	1780	1592	3371	2488	5075	7564
35	585	2149	1592	3741	2544	5075	7620

Chapter 3

Spacial vs. temporal balancing: effects of transmission expansion and storage capacity on a European power system

Abstract

Any power system that is facing the expansion of renewable energy, needs to be able to deal with an increasing frequency of mismatch between demand for electricity and power generation. Both transmission and storage can be used to balance intermittent renewable output by shifting surplus generation to deficit regions or deficit times. In this paper I study to what extent temporal balancing via storage can substitute spacial balancing via transmission in the network with expanding renewable capacities. To do so, I apply a storage heuristic for various combinations of renewable capacity and energy capacity of storage under different transmission constraints. This allows me to compare several system indicators – renewable penetration, curtailment rates, and the minimum conventional back-up requirements. For the storage capacity limited by 2.6 TWh, or the sum of existing pumped storage capacity plus realizable potential for pumped storage, each indicator demonstrates a relatively modest effect of temporal balancing. In contrast, transmission expansion has a significant potential in mitigating curtailment rates, increasing the penetration of renewables and reducing the need for conventional back-up.

Keywords: renewable energy, energy transition, electricity transmission, power storage

3.1 Introduction

Decarbonization, envisioned by European Union, goes hand in hand with an increasing reliance on renewable energy sources. In 2016 renewables, including hydro, accounted to just 29.6% of electricity generation in EU-28 (European Commission, 2018c). For 2030, the binding target share of at least 27% of renewable energy in final energy consumption translates into at least 49% of renewables in electricity generation (European Commission, 2014c).[42] Since no substantial growth of hydro power is expected (Lehner et al., 2005; Becker et al., 2014), the key role in this expansion will be played by such renewable energy sources (RES) as wind and solar.

The expansion of intermittent RES energy increases the frequency of mismatch between demand and generation. Power system needs to be able to deal with both insufficient and surplus RES output. A solution could be a combination of conventional back-up capacities and some form of balancing - be it spacial or temporal. Balancing via expansion of either network or storage enables surplus RES generation to be shifted to regions (or times) with unfavourable weather conditions. As a result there is less curtailment in the network, and the need for conventional back-up is reduced. The exact optimal combination of these three options depends on a multitude of assumptions about the power system and is a subject of abundant research literature. In this paper I refrain from determining an optimum, and instead focus on the trade-offs related to the expansion of RES power. My research question concerns the extent of substitution between transmission and storage. To investigate it, I use a simple storage heuristic for various combinations of installed RES capacity and energy capacity of storage and compare several system indicators under different transmission constraints.

The paper proceeds in the following way. Section 3.2 presents the literature review. Next, in section 3.3, I describe the methodology and data used. In the next sections I present the results of storage heuristic and compare the effects of temporal balancing with storage and spacial balancing with transmission on such system characteristics as curtailment rates, RES penetration and conventional back-up requirements. Section 3.7 discusses limitations of presented analysis, including possible biases due to the assumptions made. Finally, section 3.8 concludes.

[42]The binding final energy consumption target has recently been updated from at least 27% of renewable energy to at least 32% (European Union, 2018; European Commission, 2018a).

3.2 Literature review

RES expansion stresses the need to address the challenge of intermittent energy supply. While storage can be used to shift surplus RES generation in time, with transmission expansion RES output is aggregated over the larger the area, resulting in smoother generation profiles (Bremen, 2010; Fraunhofer IWES, 2015). This effect of reduced variability leads to lower requirements on conventional back-up power (Becker et al., 2014; Hagspiel et al., 2017; Schaber et al., 2012).

Research literature, that incorporates transmission and storage in the task of RES integration, is abundant and has been a subject of several reviews (Haas et al., 2017; Zerrahn and Schill, 2017; Cebulla et al., 2018). Often these studies look for an optimal system configuration. Although optimal storage requirements tend to be moderate when RES energy accounts for up to 50-70% of power supply (Zerrahn and Schill, 2017), they still depend on assumptions made. For example, an optimization problem can specify the investment costs in power plants and storage, fuel cost for conventional generators, price for CO2 certificates, efficiency of power plants and storage facilities, etc. The resulting optimal storage requirements can vary a lot. Consider a review by Cebulla et al. (2018), that summarizes results of over 400 scenarios from 17 studies (all but one with optimization) on storage expansion. For a given share of RES in generation mix of each geographical region – Europe, Germany or U.S. – optimal storage requirements differ widely: for example, for 40% RES in generation mix in Europe estimates for optimal storage lie between 25 and 500 GWh. For Germany the dependence of optimum on model assumptions can be illustrated by the debate around the feasibility of RES expansion. The study by Sinn (2017) estimates that for Germany to reach the target of 50% RES in electricity consumption it would require storage with 2.1 TWh of energy capacity – or construction of more than 1900 extra pumped storage plants. But Sinn (2017) does not allow for any curtailment of RES. Zerrahn et al. (2018) remove this assumption and arrive at an estimate of only 35 GWh of storage – less than existing 38 GWh of pumped storage – required to reach the same RES target.

Assumptions in the optimization problem matter for its solution, but in a fixed set of assumptions spacial balancing with transmission tends to behave as a substitute to temporal balancing through storage (Fürsch et al., 2013; Cebulla et al., 2018). The explanation lies in the generation mix. In networks with limited transmission optimal generation mix has more PV power built close to demand locations, as opposed to expanded, wind-oriented networks (Schlachtberger et al., 2017; Hörsch and Brown, 2017). Since PV output is more geographically correlated, PV-dominated mixes require larger storage than wind-dominated ones (Cebulla et al., 2018). Once artificial limits on the network are removed, and transmission expansion is possible, preference for it over storage can be traced back to model parameters, as grid expansion is usually cheaper than storage (Cebulla et al., 2018). But cost assumptions on transmission are subject to frequent and justified criticism: transmission lines are slow projects, vulnerable to social objection and taking 5–10 years on average to complete (Heard et al., 2017). It is not entirely clear to what degree the relationship between transmission and storage in the optimum, that can be found in the literature, is driven by cost assumptions.

Hence it is reasonable to study the substitution between transmission and storage without performing an optimization. Such analysis can offer additional insights into the functioning of possible future network configurations.

3.3 Methodology and data

Under favourable weather conditions the expansion of RES capacities can lead to RES generation exceeding immediate consumption. Instead of being curtailed, this surplus output can be stored. There are several ways to model storage operation. One is to optimize charging and discharging of storage to ensure better integration of RES surpluses. Uncertainty of future RES supply can be considered, although usually the literature uses a deterministic approach (Haas et al., 2017). In contrast to this optimization approach, in this paper I use a myopic storage heuristic. Any current RES output exceeding load is stored as long as the storage capacity permits and is curtailed otherwise. Once residual load – the difference between load and RES generation – is positive, energy is released from storage, displacing conventional generation.[43] The level of power in storage is equal to zero at the beginning of the year and can be positive at the end.

This paper applies myopic storage heuristic to the European network of 19 countries. Included are Germany, Austria, Belgium, Switzerland, Czech republic, Denmark, Spain, Finland, France, Great Britain, Hungary, Italy, the Netherlands, Norway, Poland, Portugal, Sweden, Slovenia and Slovakia. As a shorthand, further on in this paper they are referred to as "Europe". While the aim was to cover as many countries as possible, the choice set was ultimately limited by data availability. To apply the storage heuristic for this (or any) region I need to set values of two parameters - RES capacity and energy capacity of storage. The first determines the volume of surplus RES output produced in the system, the second - the

[43] Examples of both myopic and optimally sheduled storage can be found in Zerrahn et al. (2018)

ability of the system to shift consumption of surplus RES in time. Both variable parameters enter the myopic storage heuristic at total European levels. They are then distributed among countries according to electricity demand: countries with high demand are assumed to have more installed RES and larger volume of storage. Each country is represented as a single node. To study the effect of cross border transmission I consider two cases. The first one assumes that there is no cross border trade, and each country has to perform the storage heuristic on its own. In the second case markets in the network are fully integrated, with cross border lines able to accommodate whatever flows necessary, and the storage heuristic is implemented for the whole region. Further in this paper these two cases are referred to as autarky and copper plate, respectively.

Now let's consider the parameters of storage heuristic in more detail. Installed RES is the first of them. To apply the myopic storage heuristic, I need to determine the volume of surplus RES output produced in the system. To calculate it I combine historical load data from ENTSO-E (2018a) with RES generation. To get the latter, I use the results of reanalysis done by Staffell and Pfenninger (2016c) and Pfenninger and Staffell (2016), available online as a database[44]. They provide hourly historical capacity factors for on- and offshore wind and PV for the EU-28 plus Norway and Switzerland, based on NASA's MERRA-2 dataset.[45] Therefore to get RES generation I need to choose a year, that will give me load and weather patterns, and to make an assumption on the level of RES generation installed. In the following sections most of the results refer to the year 2014, with additional calculations provided for 2012-2014. In this paper I consider a range of installed RES capacities. As a starting point, in 2016 there was 242.3 GW of installed wind and PV in the studied countries (European Commission, 2018c; ENTSO-E, 2018b). To scale up RES capacities I need to make an assumption on how they are distributed between technologies – onshore, offshore wind and PV – within each country. For this purpose I use weights based on the analysis by Fraunhofer IWES (2015), performed on behalf of Agora Energiewende. They study the flexibility requirements arising from the 2030 target of about 50% of RES in the power supply. In particular, they assume that by 2030 the sum of wind onshore, wind offshore and PV in the studied countries will increase more than twofold, up to 522 GW. Capacity levels for different tech-

[44]Renewables.ninja (2018), `https://www.renewables.ninja/downloads`, see also Staffell and Pfenninger (2016b) and Staffell and Pfenninger (2016a).

[45]Staffell and Pfenninger (2016c) provide several versions of wind capacity factors. I use the one based on what they call "near-term" future wind fleet (current wind fleet plus under construction or with planning approval as of December 2016, see Renewables.ninja (2018)). Renewables.ninja (2018) provides two PV capacity factors datasets, based on two different meteorological sources: NASA's MERRA-2 and Meteosat-based CM-SAF SARAH satellite. However, Pfenninger and Staffell (2016) state that MEERA-2 version is more consistent on a long-term basis, therefore I use it.

nologies in Fraunhofer IWES (2015) come from national grid development plans and national energy strategy documents (for Austria, Germany, France and partially the Netherlands), and from the "green transition" vision of ENTSO-E (2014) for the rest.[46]

The second variable parameter in the storage heuristic is the energy capacity of storage. I scale up the energy capacity of storage to demonstrate what effects it can have on the network. While power capacity refers to the instantaneous electricity flow, the energy capacity of storage deals with power integrated over time. Essentially, this is the volume of storage. Since in the future we would like to use storage to shift surplus RES generation form periods with favourable weather conditions to prolonged periods of lull and dark hours, the energy capacity of storage will be the binding constraint. Currently, energy capacity of pumped storage in Europe is no more than 327 GWh (Sinn, 2017; European Commission, 2016). In this paper I set the upper limit on the range of possible storage volume values at 2.6 TWh. This is approximately equal to the sum of existing pumped storage capacity plus 2291 GWh of realizable potential for pumped storage in EU-15, Switzerland and Norway (van de Vegte, 2015).[47] This number is also comparable to 3 TWh of maximum estimates for the optimal energy capacity of storage needed in Europe under different scenarios (Cebulla et al., 2018).[48]

Given the values of two variable parameters – RES capacity and energy capacity of storage – the storage heuristic produces an output in form of a time series of conventional dispatch and RES curtailment. Finally, using this output, I calculate several indicators. The first is the curtailment rate - curtailed RES generation divided by total RES generation. It estimates the percentage of the RES generation that is ultimately wasted - i.e., neither consumer nor stored.[49] The second system indicator is the share of consumed RES generation in the total annual electricity demand, or RES penetration. It estimates the percentage of the load that is covered with either simultaneous RES generation or with RES energy released from storage.[50] The third indicator is the maximum hourly mismatch between the load on one hand

[46]See table 6, page 81, in Fraunhofer IWES (2015).

[47]EU-15 in van de Vegte (2015) includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden and United Kingdom.

[48]See Cebulla et al. (2018), excluding extreme outliers with high RES shares and CO2 certificate price of 400 €/t.

[49]Curtailment rate in copper plate is equal to the RES generation curtailed, assuming no transmission constraints between the countries, divided by the total RES generation. Curtailment rate in autarky is equal to the sum of RES generation curtailed in each country, assuming no transmission between the countries, divided by the total RES generation.

[50]Given installed RES capacity, the storage heuristic allows me to calculate the total conventional dispatch divided by total load. The RES penetration is equal to one minus this fraction. In copper plate case, no transmission

and RES generation and possible storage discharge on the other - the minimal conventional capacity that should be installed to avoid a blackout. Appendix C.1 provides calculation results for Germany, while appendix C.2 provides extra tables with calculation results.

3.4 Curtailment

Whatever the future combination of cross border transmission, storage and RES installed in Europe will be, it will most likely result in some level of curtailment. Curtailment occurs when there is a lack of demand or if the network constraints do not allow for all of the RES generation to be injected. As a result, some of the RES output is lost. This loss can be viewed negatively, especially when curtailment is associated with financial costs, as it is the case with curtailment as a result of feed-in management measures in Germany.[51] Yet, in a sense, curtailment is not a new phenomenon, as conventional power plants are limited by dispatch decisions. For example, in 2018 the capacity factor of hard coal in Germany was 34.7% - higher than 21.5% for wind but still far from 100%.[52] Nevertheless, RES curtailment is different in that RES energy comes at a zero marginal cost, making storage a potentially attractive alternative to wasting this energy. But to what extent should the storage be deployed? Should a power system try to avoid curtailment altogether? After all, European policies focus on the consumption of RES energy, and for the same level of installed RES capacity lower levels of curtailment translate into higher RES penetration.

In this section I present curtailment rates, calculated for the storage policy described in the previous section, assuming that there is no congestion within each country. Figure 3.1 plots iso curves for the possible combinations of installed RES capacity and storage capacity for the fully integrated network (figure 3.1 (a)) and autarky case (figure 3.1 (b)) in Europe. The almost vertical character of iso curves suggests that the temporal effect of storage on curtailment rate is far less than the effect of spatial balancing. The latter can be observed in the horisontal comparison of figures 3.1 (a) and (b): given the level of storage capacity, curtailment rates are lower in the fully integrated network for the same levels of installed RES. For example, 1000 GW installed RES will result in less than 10% curtailment with no transmission constraints compared to 10-20% in autarky.

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constraints are assumed in the heuristic. In autarky case, there is no transmission between countries.

[51] According to Bundesnetzagentur and Bundeskartellamt (2017b), curtailment rate of 2.3% in 2016 lead to an estimated 373m € o compensation to RES operators under the German legal framework.

[52] Own calculations based on Fraunhofer ISE (2018) data.

Figure 3.1: Iso curves of European curtailment rates (%), depending on storage and installed capacity of RES

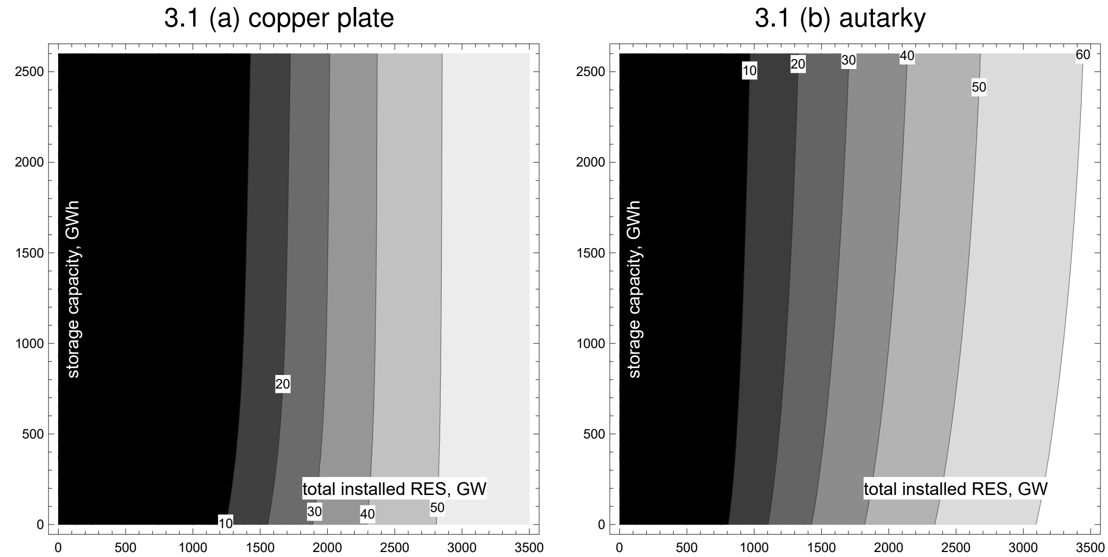
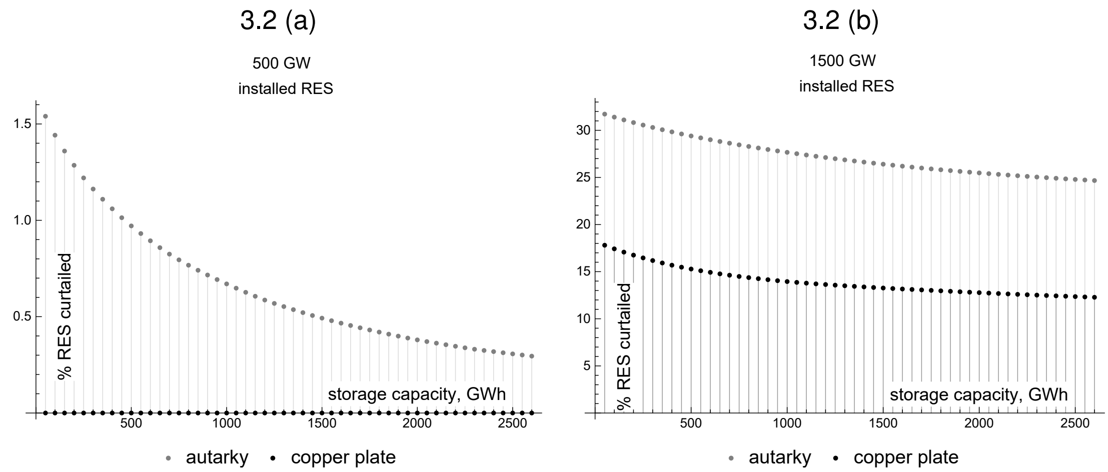


Figure 3.2: RES curtailment rates (%), depending on the energy capacity of storage



Intuition suggests that the more storage capacity is added, the lower the curtailment is, given the same level of installed RES. This hypothesis is explored in figures 3.2 (a) and (b). Figure 3.2 (a) plots curtailment rate in copper plate and autarky at 500 GW RES installed. This is almost twice as high as RES capacities installed in 2016 and close to what Fraunhofer IWES (2015) proposed for 2030. For the weather pattern of 2014 it gives an annual RES generation of 992 TWh, or 35% of total electricity demand of 2829 TWh in the same year. At this “low” (compared to figure 3.2 (b)) level of installed capacity curtailment in the fully integrated network is non-existent for any storage level considered. If there is any surplus RES in one region, it is simply transferred to and consumed in deficit regions. There is no spacial balancing in autarky, and curtailment is at 1.6% without storage, falling to 0.3% at 2600 GWh storage capacity. Figure 3.2 (b) plots curtailment rate at 1500 GW installed RES. For the weather pattern of 2014 this level of installed RES leads to 2977 TWh of annual RES generation. Nevertheless, even with 2600 GWh of storage capacity curtailment is 24.7% in autarky and 12.3% in the fully integrated network, falling from 32% and 18.2% respectivelly at zero storage. At first this may look counter-intuitive, as annual RES generation is only 5% larger than the annual electricity demand. However, although RES displays smoothing effect over large areas, outputs in neighbouring countries are correlated (Fraunhofer IWES, 2015). Coinciding peaks of RES infeed fill the storage up to its capacity. As a result, for 2302 hours (26% of the year) the storage capacity constraint is binding. Binding storage constraint, in turn, leads to curtailment, that can be mitigated by network expansion.

Figures 3.3 (a) and (b) further illustrate the dependence of curtailment rate on installed RES capacity. Initially, when installed RES capacities are relatively low, so are the surplus RES generation and curtailment rates. In contrast, at high levels of installed RES a large part of RES output is neither consumed nor stored, leading to high curtailment rates. Although there is no storage in figure 3.3 (a), as opposed to 2600 GWh of storage capacity in figure 3.3 (b), the curtailment does not change dramatically between these two figures. In both plots, independently of transmission in the network, curtailment rate is close to zero for installed RES doubled from 2016 levels (about 500 GW) and converges to approximately the same levels for high values of installed RES. Even though in the fully integrated network RES energy is consumed more efficiently due to spatial balancing, eventually surplus RES generation is too large in relation to the storage capacity, and the greater part of RES output is curtailed.

In the future, past 2030, one can expect installed RES to lie between those two extremes. In this case, on one hand, a large part of the electricity demand is satisfied by RES output, and on the other - curtailment is not extremely high. It is in this middle range of installed RES that both storage capacity and cross border transmission can have noticeable effect

Figure 3.3: RES curtailment rates (%), depending on installed capacity of RES

3.3 (a) 3.3 (b)

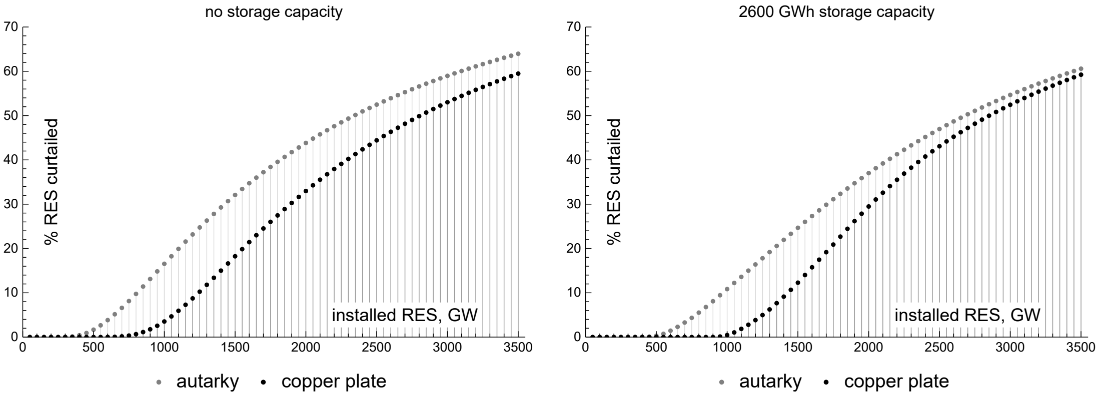
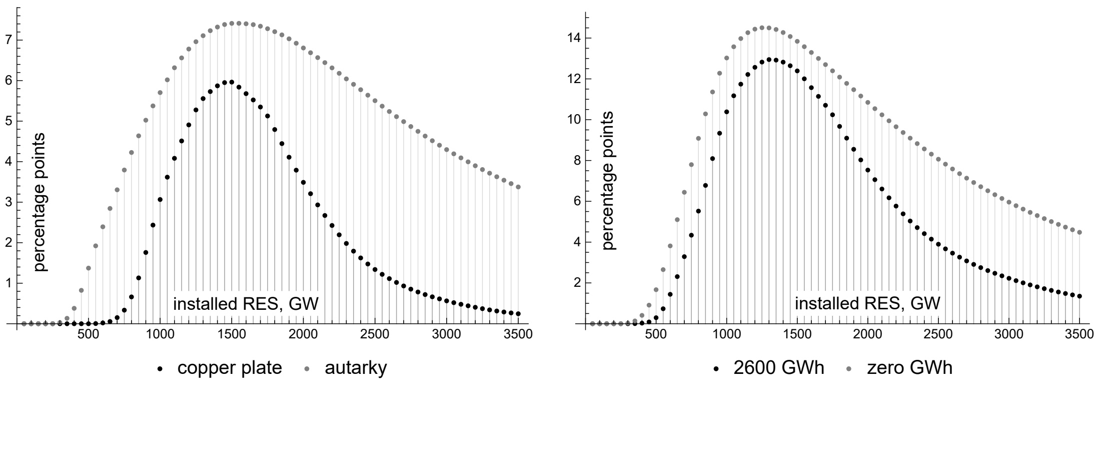


Figure 3.4: Difference in curtailment rates, depending on installed capacity of RES

3.4 (a) curtailment at zero storage minus curtailment at 2600 GWh storage

3.4 (b) curtailment in autarky minus curtailment in copper plate



on curtailment. Figures 3.4 (a) and (b) aim to separate the temporal effect of storage and the spacial balancing effect of transmission in figures 3.3 (a) and (b). The temporal effect of storage is plotted in figure 3.4 (a). At its peak, in autarky an increase in storage capacity from zero GWh to 2600 GWh reduces the curtailment rate by 7.4 percentage points, from 32% to 24.7%. In the fully integrated network curtailment is already lower due to spacial balancing, hence extra storage capacity leads to a reduction of 5.9 percentage points, from 18.2% to 12.3%. Spacial balancing, plotted in figure 3.4 (b), has a greater magnitude compared to the temporal one. Switching from none to unlimited transmission in the network at zero GWh storage capacity reduces curtailment rate by 14.5 percentage points, from 26.3% to 11.8%. At 2600 GWh storage capacity the reduction is 13 percentage points, from 19.2%, to 6.2%. The less storage there is, the greater the spacial balancing effect.

Of course, it is possible to completely eliminate curtailment if the energy capacity of storage is large enough to store the full volume of surplus RES generation. However, it may not only be economically unreasonable, as shown by Zerrahn et al. (2018), but also not feasible as storage volume will fast soar beyond the European pumped storage potential (Sinn, 2017). The higher the RES penetration that we would like to have in Europe, the more RES needs to be installed, the more persistent curtailment will be. As this section demonstrates, curtailment can be mitigated by temporal balancing, but to a lesser extent than by spacial balancing. It is beyond the scope of this paper to answer to what extent curtailment will affect the investment incentives of market participants. As a possible solution, RES generators can provide energy in other markets, apart from electricity. Using electricity, for example, in heating or transport sectors, can reduce curtailment and give extra profits for RES generators. At the same time, such sector coupling will change load patterns, increase overall demand for electricity, and consequently negatively affect the achievement of any possible RES penetration targets.

3.5 RES penetration targets

European policy targets focus on how much RES energy is consumed in the network (European Council, 2014). For 2030 the binding target of at least 27% of RES in final energy consumption corresponds to at least 49% of RES in electricity generation (European Commission, 2014c). In this section I discuss the substitution between storage and transmission expansion in the context of their effects on RES penetration - the share of electricity demand covered with either simultaneous RES generation or with RES energy released from storage. Note that in this paper I only focus on wind and PV power. Due to the lack of data I do not estimate the hydro power output, that would normally be added to RES statistics. Since in

2016 hydro power accounted for 11.5% of total electricity generation[53], and given that no substantial growth of it is expected, my estimates for the RES penetration are approximately 10% lower than those that would account for hydro power.

3.5.1 RES target achievement without storage

Consider a country striving to achieve a certain level of RES penetration. Although achieving such target is easier with storage, assume for a moment that there is none. The network has a trade off between expanding either installed RES capacity or cross border transmission. Table 3.1 presents the installed RES capacity, required to reach different levels of RES penetration in 19 European countries. The calculations are done for the fully integrated European network (*CP* rows) and two versions of European autarky. In rows Aut_i each country has to achieve the target. In rows Aut_e, like in Aut_i, there are no flows between the countries, but now only the total European target on RES penetration matters.

The most important result is that the capacity requirement is not only higher in both versions of autarky, but the gap between autarky and the fully integrated network increases dramatically for the higher RES penetration.

Consider the penetration levels of 20% and 50%. To reach a goal of 20% RES in electricity demand, in the fully integrated network we need 285 GW RES installed, which is 18% more than 242.3 GW installed in 2016. The same extra capacity is needed in case of autarky with target achievement on European level (Aut_e). In a more demanding case when each country needs to achieve the target in autarky (Aut_i) we need 314 GW installed - 30% more than there was in 2016, or 10% more than in the fully integrated network. The 50% target is even harder to achieve without cross border flows. In the fully integrated network it requires 714 GW RES installed. In the mild version of autarky (Aut_e) we need 10% more RES, or 786 GW installed; in the more demanding version of autarky (Aut_i) - 868 GW installed, or 22% more than in the fully integrated network. Choosing a different year (or years) for analysis does not change the results a lot. The bottom half of the table 3.1 shows results for the 2012-2014 load and weather patterns. Here the extra installed RES, required to reach the target in each country in autarky, as opposed to the fully integrated network, goes up from 9% (311 GW vs. 285 GW) to 20% (859 GW vs. 715 GW). The gap goes well beyond 250% more for the 90% target.

[53] See European Commission (2018c), pages 91 and 121.

Table 3.1: RES penetration (r, in %) and system characteristics

r	0.	10	20	30	40	50	60	70	80	90	99
RES installed, GW. 2014 data											
Aut_i	0	157	314	473	649	868	1178	1654	2504	4755	263448
Aut_e	0	143	285	431	592	786	1043	1426	2111	3975	31579
CP	0	143	285	428	570	714	867	1046	1287	1699	3071
RES curtailed, %. 2014 data											
Aut_i	0	0.	0.	1.2	5.1	12.	22.5	36.1	52.5	72.5	99.5
Aut_e	0	0.	0.	0.7	3.6	9.3	18.	30.	46.	67.7	95.5
CP	0	0.	0.	0.	0.	0.2	1.3	4.6	11.4	24.5	54.
RES installed, GW. 2012-2014 data											
Aut_i	0	156	311	469	642	859	1167	1644	2498	4718	176091
Aut_e	0	143	286	431	590	782	1036	1415	2098	3937	31675
CP	0	143	285	428	571	715	869	1050	1291	1694	3028
RES curtailed, %. 2012-2014 data											
Aut_i	0	0.	0.	1.2	4.9	11.7	22.1	35.8	52.4	72.3	99.2
Aut_e	0	0.	0.	0.7	3.6	9.2	17.8	29.7	45.7	67.4	95.5
CP	0	0.	0.	0.	0.	0.2	1.3	4.7	11.5	24.3	53.4

These results demonstrate the spacial balancing effect on RES target achievement. For the same level of RES installed, unlimited transmission capacities enable the network to reach higher RES targets. More over, this effect becomes more prominent at higher targets. As shown in section 3.4, spacial balancing reduces the need to curtail RES due to the absence of network constraints. As less power is curtailed, a larger part of RES generation is consumed for the same level of installed capacity. The balancing effect of transmission underlines the importance of cross border connections. If Europe plans to press for higher RES energy targets, the choice has to be made between expanding national RES capacities and expanding cross border lines. The next subsection investigates if storage expansion can change this conclusion and substitute network expansion.

3.5.2 RES target achievement with storage

Assume that some expandable storage technology is available. With storage, a country needs less installed RES to reach the same target of RES penetration. As storage capacity is expanded, less RES power needs to be curtailed, and for the same level of installed RES capacity more surplus RES power is stored, to be released into the network as soon as the residual load is positive. Let's look at the substitution between cross border transmission and storage for a given level of installed RES capacity.

Figures 3.5 and 3.6 plot the iso curves for the trade-off between installed RES capacity and storage capacity in a fully integrated network (figure 3.6) and an autarky case (figure 3.5) in Europe. Each curve shows all the possible combinations of European values for storage and installed RES capacity that result in a certain level of RES penetration. Both figures are based on 2014 load and weather data. The values along horizontal axes in figure 3.5 (3.6) correspond to the row Aut_e (CP) in table 3.1. Each of these figures can be interpreted as a feasible region of an optimization problem: to reach a certain target at a minimal cost the iso curves would have to be complemented by a negatively sloping budget constraint, with a tangent point indicating solution.

Both figures demonstrate that storage does not have a noticeable effect for a wide range of installed RES. Even at 1000 GW - approximately fourfold increase of current RES capacities and doubled of what is proposed for 2030 by Fraunhofer IWES (2015) - iso curves are vertical. There is not enough surplus RES generated for the temporal balancing to be detectable. Spacial balancing too relies on surplus RES output, but, as seen in table 3.1, it already has a prominent effect on target achievement at around 1000 GW RES installed.

How does temporal balancing compare against spacial one in general? To what extent can storage substitute the network expansion? Figure 3.7 aims to separate the temporal effect of storage and the spacial balancing effect of transmission in figures 3.6 and 3.5. It depicts the difference in RES penetration between the fully integrated network and the autarky case for zero and 2600 GWh storage capacity. I.e., it shows the potential to improve the RES penetration by expanding either network or storage.

For relatively "low" levels of installed RES all four combinations of transmission and storage in the network lead to indistinguishable outcomes. This range includes 242.3 GW RES installed in 2016 that result in 17% of RES penetration independently of both transmission and storage capacities. From about 500 GW RES installed there is enough surplus RES in the network for both spacial and temporal balancing to have an effect on RES penetration. In particular, spacial balancing starts to play a prominent role. With no constraints on cross border transmission, previously curtailed power is now consumed in deficit regions and is accounted for in RES penetration. At its peak spacial balancing helps to increase the penetration rate by 15.2 percentage points with no storage available and by 13.1 percentage

Figure 3.5: Iso curves of RES penetration (%), depending on storage and installed capacity of RES, autarky

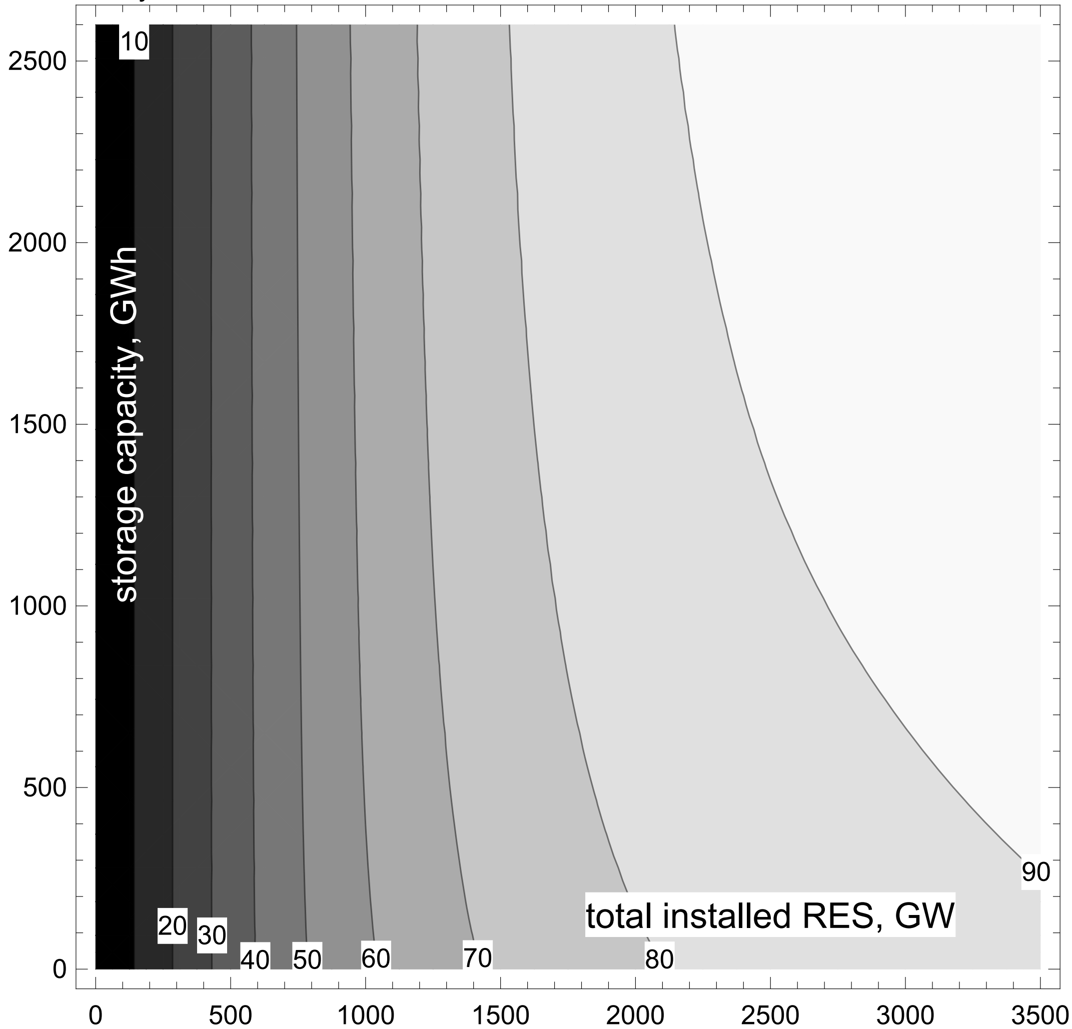
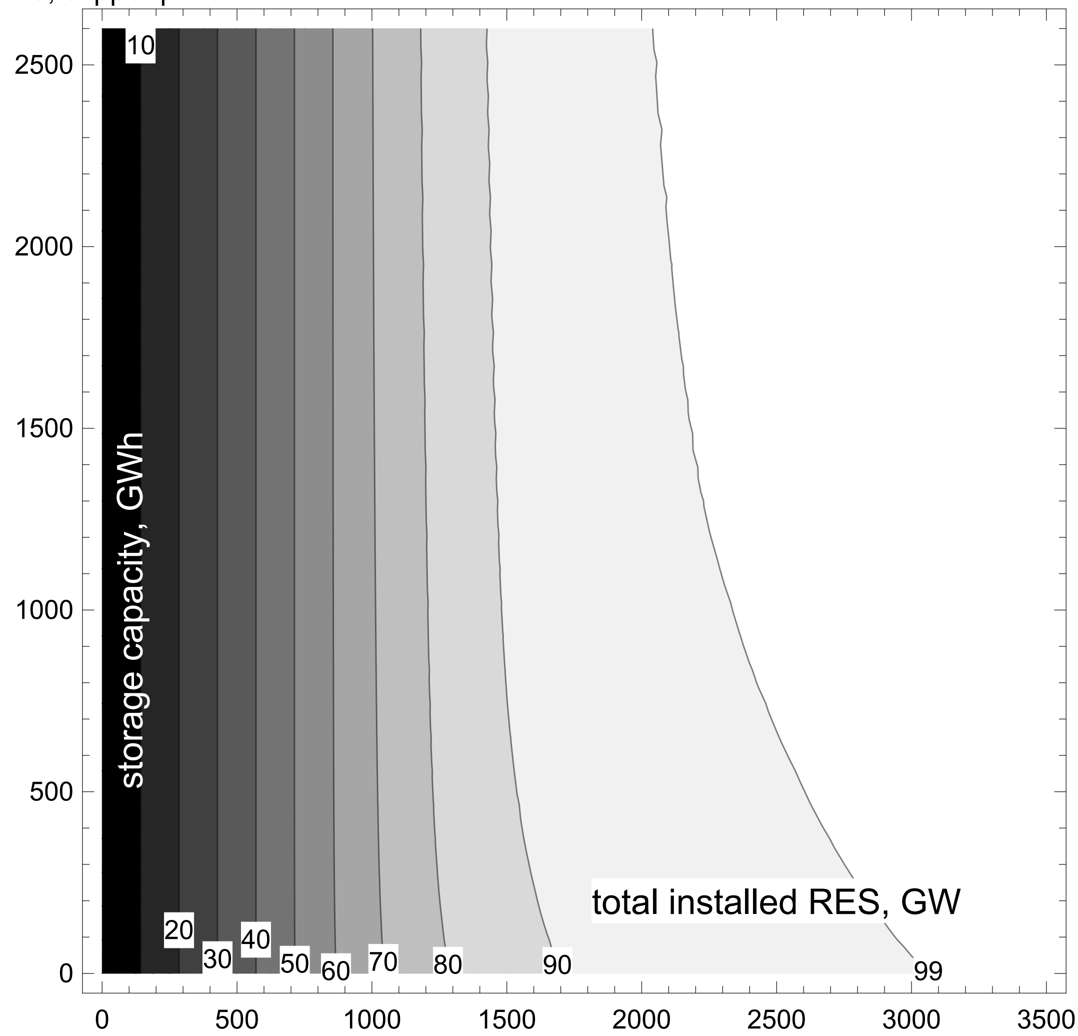


Figure 3.6: Iso curves of RES penetration (%), depending on storage and installed capacity of RES, copper plate



points with 2600 GWh storage. Before the peak, the additional effect from storage is small compared to the spacial balancing: the gap between “no storage” and “2600 GWh storage capacity” curves is about 2 percentage points. Once the peak of the spacial balancing is reached, the effect of storage becomes larger with the gap between “no storage” and “2600 GWh storage capacity” increasing up to about 7 percentage points.

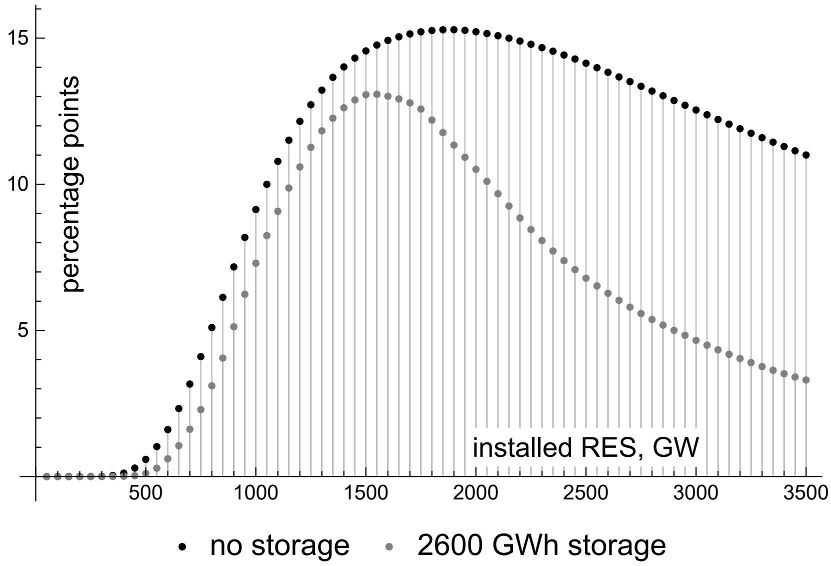
Consider the following example. If there are 1000 GW RES installed in the network, without cross border trade RES penetration will be 58.5% with zero storage and 62.5% with 2600 GWh of storage. Expanding the network to the point there transmission constraints are no longer binding will increase the RES penetration to 67.7% with zero storage and to 69.8% with 2600 GWh of storage. In contrast, if there are 3000 GW RES installed in the network, without cross border trade RES penetration will be 86.3% with zero storage and 95.3% with 2600 GWh of storage; while network expansion can increase the RES penetration to 98.8% with zero storage and to 99.9% with 2600 GWh of storage. Additional calculations demonstrate that the effect of spacial balancing on RES penetration, plotted in the figure 3.7, is persistent to storage expansion. For 1350-1600 GW RES installed, network expansion will still give 10 or more extra percentage points of RES penetration even if storage volume is equal to 100 TWh.

These results demonstrate that the temporal balancing can hardly substitute the line expansion in the task of increasing RES penetration. Cross border connections in the network are important. Although increasing storage volume up to the full potential does have a positive effect on the RES penetration, it is small compared to what network expansion can achieve.

3.5.3 RES expansion and storage

One should be warned against making a conclusion that near vertical slope of iso curves in figures 3.5 and 3.6 means that storage has little to offer for the foreseeable future. In this analysis each country is treated as a single node, i.e. no congestion is assumed to take place within each country. This assumption does not hold in practice. For example, in Germany on average 2.7% of RES generation had to be curtailed each year between 2015 and 2017, because network capacities were not sufficient to transport the total amount of electricity generated (Bundesnetzagentur and Bundeskartellamt, 2017b, 2019). Non-zero curtailment has also been observed in such European countries as Spain and Italy (Bird et al., 2016). Therefore the results, reported in section 3.4, should be treated as a lower bound on future curtailment rates in Europe.

Figure 3.7: Difference in RES penetration between copper plate and autarky cases



The results in sections 3.4 and 3.5 highlight the following: high RES penetration targets require high levels of installed RES capacity. However, electrical storage has, for the most part, minor effect on required RES expansion. At the same time, RES expansion comes together with high curtailment rates. As was already mentioned above in section 3.4, there is a potential for sector coupling - utilizing surplus RES energy in other markets, apart from electricity. Sector coupling will reduce curtailment and change load patterns, potentially alleviating congestion within countries. But sector coupling will also increase the demand for electricity. This may be an important side effect for some states: for example German legislation sets RES targets in terms of gross electricity consumption (the renewable energy sources act, Erneuerbare Energien Gesetz (2017)), and not in terms of final energy consumption as in the European Union (European Union, 2018).

3.6 Conventional back-up

Any combination of RES installed and storage that does not result in a fully renewable system would need some amount of conventional generation. The myopic storage heuristic is not the best policy to address the issue of conventional back-up, as it disregards the future fluctuations in RES output and does not aim to reduce peaks of residual load.

The need for conventional back-up can be measured in several ways. In terms of annual conventional generation, consider figures 3.5 and 3.6. If, for example, given the levels of RES installed and storage capacity RES penetration is between 40% and 50%, the remaining 50% to 60% of 2829 TWh of total electricity demand have to come from conventional back-up.

A more important indicator is the maximum hourly mismatch between the load on one hand and RES generation and possible storage discharge on the other. This is the maximum required conventional generation at any hour. It can also be interpreted as the minimal conventional capacity that should be installed to avoid blackouts. Since demand and weather patterns vary from year to year, any country concerned with security of energy supply will install more conventional back-up than this minimum. For example, in 2014 Germany had 76.5 GW of wind and PV installed (Fraunhofer ISE, 2018), resulting in a maximum mismatch of 76 GW. Nevertheless, installed conventional power amounted for 92.6 GW, with additional 5.6 GW provided by hydro power, and 6.9 GW - by biomass.

Two factors influence the maximum hourly mismatch between the load on one hand and RES generation and possible storage discharge on the other. The first is the installed RES capacity, the second is the storage capacity. The first creates peaks of RES generation in the network, while the second creates the ability to shift those peaks in time. Figures 3.8 (a) and (b) plot the peak hourly need for conventional dispatch depending on the energy capacity of storage. They demonstrate that the storage effect is quite moderate compared to the importance of transmission.

In figure 3.8 (a) there are 1500 GW RES installed (about 6 times more than in 2016) that generate 2977 TWh annually, or 5% more than the total electricity demand of 2829 TWh in 2014. In figure 3.8 (b) 3500 GW RES installed (about 14 times more than in 2016) generate 6947 TWh annually, or 146% more than the total electricity demand. In figure 3.8 (a) the maximum hourly mismatch stays constant independent of storage capacity - there is not enough surplus RES generated to address the prolonged time periods with RES-unfavourable weather conditions. In figure 3.8 (b) this situation improves, and the full utilization of spacial balancing together with 1700 GWh storage capacity bring the need for conventional back-up down to zero.

Of course, building up high levels of installed RES capacities so as to reduce conventional dispatch will have its cost. Consider curtailment: even with full utilization of spacial and temporal balancing it stays above 12% for 1500 GW installed RES and above 59% for 3500 GW RES (see figures 3.9 (a) and (b)). If we would like to avoid conventional back-up and associated fossil fuel use, huge amount of RES will have to be installed, and most of RES output will be curtailed, raising questions about the incentives to install RES in the first place.

Figure 3.8: Peak hourly need for conventional dispatch, GW

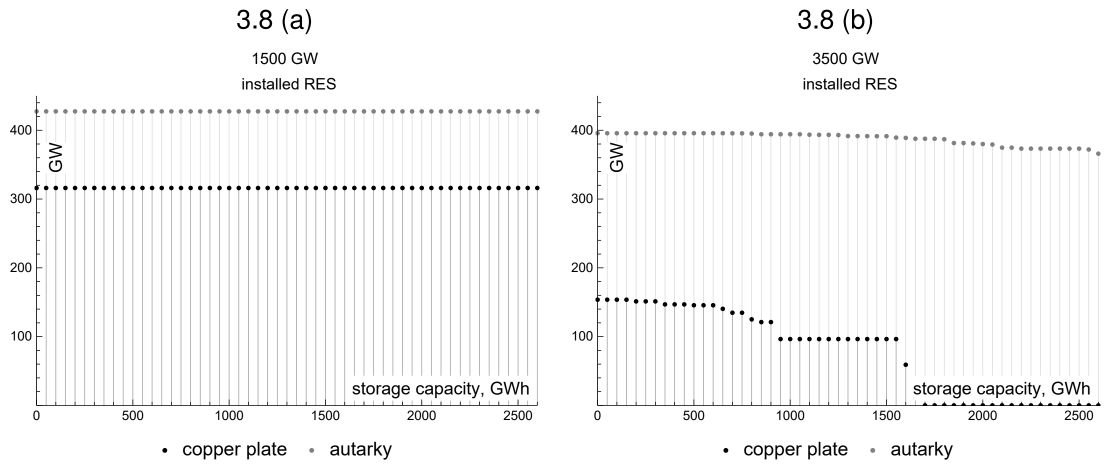
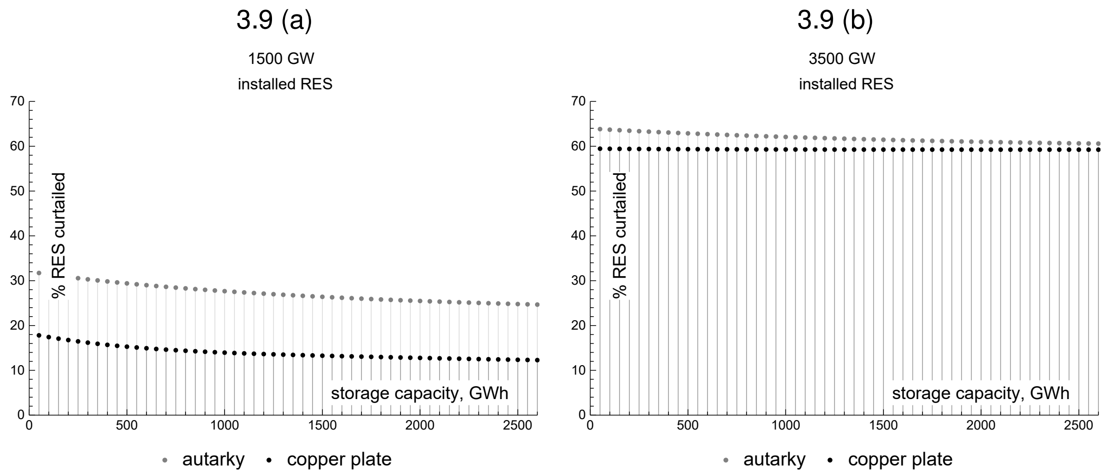


Figure 3.9: RES curtailment rates, %



3.7 Discussion

In this section I'd like to discuss limitations and biases of the study, presented above. First of all, since this paper does not focus on a particular storage technology, no assumptions were made on efficiency losses in charging and discharging.[54] Hence the results overestimate the effect of temporal balancing. As previous sections demonstrate, this bias does not help: spacial balancing has a more prominent effect than storage on curtailment rates and RES penetration.

Second, only the extreme cases of transmission usage are discussed: complete isolation of autarky vs. absence of any transmission constraints in the fully integrated network. No limited line expansion can outperform the latter, hence focus on the extreme cases does capture the full extent of spacial balancing potential. However, I intentionally do not try to answer a question of the optimal line expansion. Such attempt would require a wide range of assumptions, for example on investment costs in power plants and storage facilities, fuel cost for conventional generators, price for CO2 certificates, efficiency of power plants and storage facilities, etc. The optimal expansion of transmission lines also depends on the granularity of the model (Schlachtberger et al., 2017). The larger the scope of aggregation, the less nodes per country are there, the more weight is given to traditionally weaker cross border lines. As a consequence, models with only one node per country show bigger network expansions compared to the models with multiple nodes per country. For example, for the same cost of transmission expansion – 400 €/MWkm – one-node-per-country study by Schlachtberger et al. (2017) determines the optimal grid, that leads to a 95% CO2 reduction compared to 1990 levels, to be nine times larger than the existing one, while a higher granularity study by Hörsch and Brown (2017) - only three times larger than the existing one.[55] Hence in the set-up, used in this paper, any attempt to find the required transmission expansion will result in an upward biased estimate.

Finally, in this paper I look on the electricity sector only, and do not investigate possibilities for coupling with other sectors. Electrical storage is more expensive compared to technologies available in heating or transportation sectors (Lund et al., 2016), and sector coupling can reduce the need for electrical storage (Zerrahn et al., 2018). At the same time, sector coupling will create new demand for electricity, changing the consumption patterns and affecting

[54]For example, an overview of storage technologies including efficiency estimates can be found in Luo et al. (2015).

[55]Both Schlachtberger et al. (2017) and Hörsch and Brown (2017) measure the grid in TWkm.

Europe's ability to achieve targets on renewable energy in electricity consumption.

3.8 Conclusion

Wind and solar renewable energy is inherently intermittent. Hence their expansion inevitably forces a network to address possible mismatch between demand and generation. Spacial balancing through transmission expansion and temporal balancing through storage are often suggested as possible solutions. There is an extensive literature, dedicated to determining an optimal configuration and characteristics of power system under certain assumptions, in particular, provided a certain share of renewable energy. Although it is good to know what the first best is, extending analysis to the non-optimal states is a reasonable idea, especially since the transmission expansion projects can take several years to complete.

In this paper I presented outcomes of implementing a myopic storage heuristic in a network of 19 European countries for different combinations of transmission capacity and storage energy capacity. In particular, I have focused on three indicators: share of renewable energy in electricity demand, rate of renewable energy curtailed, and the minimum conventional generation required at any hour. Results contrast the spacial balancing and the temporal balancing, demonstrating that the former outweights the latter in the analysed range of storage capacities of up to 2.6 TWh, or the sum of existing pumped storage capacity and the realizable potential for pumped storage in EU 15, Switzerland and Norway. Spacial balancing through transmission expansion creates the possibility for European countries to reach renewable targets much faster compared to the absence of cross border trade; while temporal balancing has little effect on achievement of targets. Spacial balancing can also reduce the curtailment rates in the network to a larger extent compared to the temporal balancing. Finally, for the minimum conventional generation required at any hour, it is the spacial balancing that enables the network to completely forgo the conventional power, but only at the cost of high curtailment rates.

Repeatedly the calculations demonstrate the importance of spacial balancing of renewable power. Storage alone does not allow the network to reach penetration levels realizable with line expansion. If Europe is to continue on the journey to the high targets of renewable generation in electricity consumption, the only way to avoid the expansion of cross border lines is extremely high installed renewable and storage energy capacities.

Appendix C

Spacial vs. temporal balancing: effects of transmission expansion and storage capacity on a European power system

C.1 RES target achievement in Germany alone

This appendix presents the results of myopic storage in German power system. Load and weather data are taken from 2014, making it possible to compare the results to the study on the limits of Germany's energy revolution by Sinn (2017).

Table C.1 presents the RES capacities, required to be installed in Germany to reach different RES targets, together with associated curtailment and maximum hourly residual load – the difference between load on one hand and RES generation and possible storage discharge on the other. Results are calculated given the existing 38 GWh of pumped storage capacity (Sinn, 2017). For the reference, the German renewable energy sources act (Erneuerbare Energien Gesetz, 2017) sets the target on RES energy in gross electricity consumption at 40-45% by 2025 and at 55-60 % by 2035. To achieve the 60 % target, existing, as of 2018, 105.4 GW of installed RES (Fraunhofer ISE, 2018) would need to be more than doubled up to 215 GW. Curtailment increases from zero at the existing level of installed RES, to 9.1% at RES penetration equal to 60%, but stays below 30% for RES penetration levels of up to 80%.

As in Sinn (2017), table C.1 and figures C.1 and C.2 assume absence of internal bottlenecks in the German grid, i.e. a copper plate. Hence the curtailment results, reported in this appendix, should be treated as a lower bound on the actual curtailment rates. I will come back to this point below.

Table C.1: Characteristics of German power system at different RES penetration levels. 2014 data, 38 GWh storage capacity

RES penetration (%)	RES installed (GW)	RES curtailed (%)	maximum residual load (GW)
0	0	0	80
10	33	0.	78
20	65	0.	77
30	98	0.	75
40	132	1.	74
50	170	3.9	73
60	215	9.1	73
70	274	16.7	72
80	362	28.	71
90	567	48.3	69
99	1819	82.3	57

Figure C.1 plots the iso curves for the trade-off between installed capacity and storage in Germany based on 2014 data. Each curve shows all the possible combinations of storage and installed RES capacity that result in a certain level of RES penetration. The black dot A corresponds to the position of Germany in 2018: 105.4 GW of installed RES (Fraunhofer ISE, 2018) and 38 GWh of pumped storage capacity (Sinn, 2017). The white dot B corresponds to the storage capacity, required, according to Sinn (2017), to reach 50% RES penetration level.[56]

Again, figure C.1 assumes the absence of transmission constraints within the German grid. In reality, the German grid does have internal bottlenecks.

The impact of those bottlenecks can be tracked through the monitoring reports of the federal network agency (Bundesnetzagentur). Feed-in management, or curtailment of RES infeed in cases when network capacities were not sufficient to transport the total amount of electricity generated, has increased dramatically since 2010 (Bundesnetzagentur and Bundeskartellamt, 2019). In 2015, 2016 and 2017 curtailed energy amounted to 4.7 TWh, 3.7 TWh and 5.5 TWh (or 2.9%, 2.3% and 2.9% of RES installations eligible for payments under

[56]Sinn (2017), table 1. Note that Sinn (2017) does not report the exact level of installed RES, but the penetration level and the required storage capacity.

Erneuerbare Energien Gesetz (2017)).[57] Moreover, in Germany curtailment of RES energy has a financial dimension to it, as the operators of RES installations have to be compensated (Erneuerbare Energien Gesetz (2017), paragraph 15).[58] Therefore one should be warned against making a conclusion that the near vertical slope of iso curves in figure C.1 means that storage has little to offer for the foreseeable future. Storage provides means to avoid wasting the energy that would otherwise be curtailed. Hence it has ability to address problems related to network congestion. However, the question remains as to who would build up storage capacities. Since currently operators of RES installations are compensated in the event of curtailment, they do not have incentives to make such investments.

Avoiding curtailment by means of storage brings us to the second point. Figure C.1 can be compared to tables 1 and 2 in the study by Sinn (2017) on the the limits of German Energiewende. In his calculations, Sinn (2017) excludes the possibility of curtailment - apart from a 25% "round-trip" efficiency loss, all surplus RES energy has to be stored in pumped storage. In table 1 Sinn (2017) provides estimated energy capacity of storage, required in Germany given a certain level of RES penetration. In table 2 Sinn (2017) expands his estimations to cases there fluctuations in German RES supply are balanced, as much as it is possible, by conventional plants and hydro dams in neighbouring countries with no constraints on transmission capacity. As in chapter 3 of this thesis, the calculations in Sinn (2017) rely on 2014 data.[59] Remember, the upper limit of the vertical axis in figure C.1 is 2.6 TWh, which is approximately equal to the sum of existing pumped storage capacity in Europe plus 2291 GWh of realizable potential for pumped storage in EU-15, Switzerland and Norway (van de Vegte, 2015).[60] The estimates of required storage in the study by Sinn (2017) are extremely high. According to them, just for Germany alone, the required storage capacity exceeds the 2.6 TWh limit for RES penetration levels above 52.5% (if Germany is isolated from its neighbours) or above 67.6% (if Norway, Austria, Switzerland and Denmark help Germany to balance fluctuations of its RES generation).

[57] See Bundesnetzagentur and Bundeskartellamt (2017a), Bundesnetzagentur and Bundeskartellamt (2017b), Bundesnetzagentur and Bundeskartellamt (2019).

[58] Curtailment of 4.7 TWh, 3.7 TWh and 5.5 TWh (or 2.9%, 2.3% and 2.9% of RES installations eligible for payments under Erneuerbare Energien Gesetz (2017)) in, accordingly, 2015, 2016 and 2017 (Bundesnetzagentur and Bundeskartellamt (2019), page 141) corresponds to estimated 478m€, 373m€ and 609.9m€ in compensations (Bundesnetzagentur and Bundeskartellamt, 2017a,b, 2019).

[59] The main difference in data is that while Sinn (2017) takes actual RES generation data from TSO's, I use estimates of capacity factors from Renewables.ninja (2018).

[60] EU-15 in van de Vegte (2015) includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden and United Kingdom.

Figure C.1: Iso curves of RES penetration (%), depending on storage and installed capacity of RES, Germany

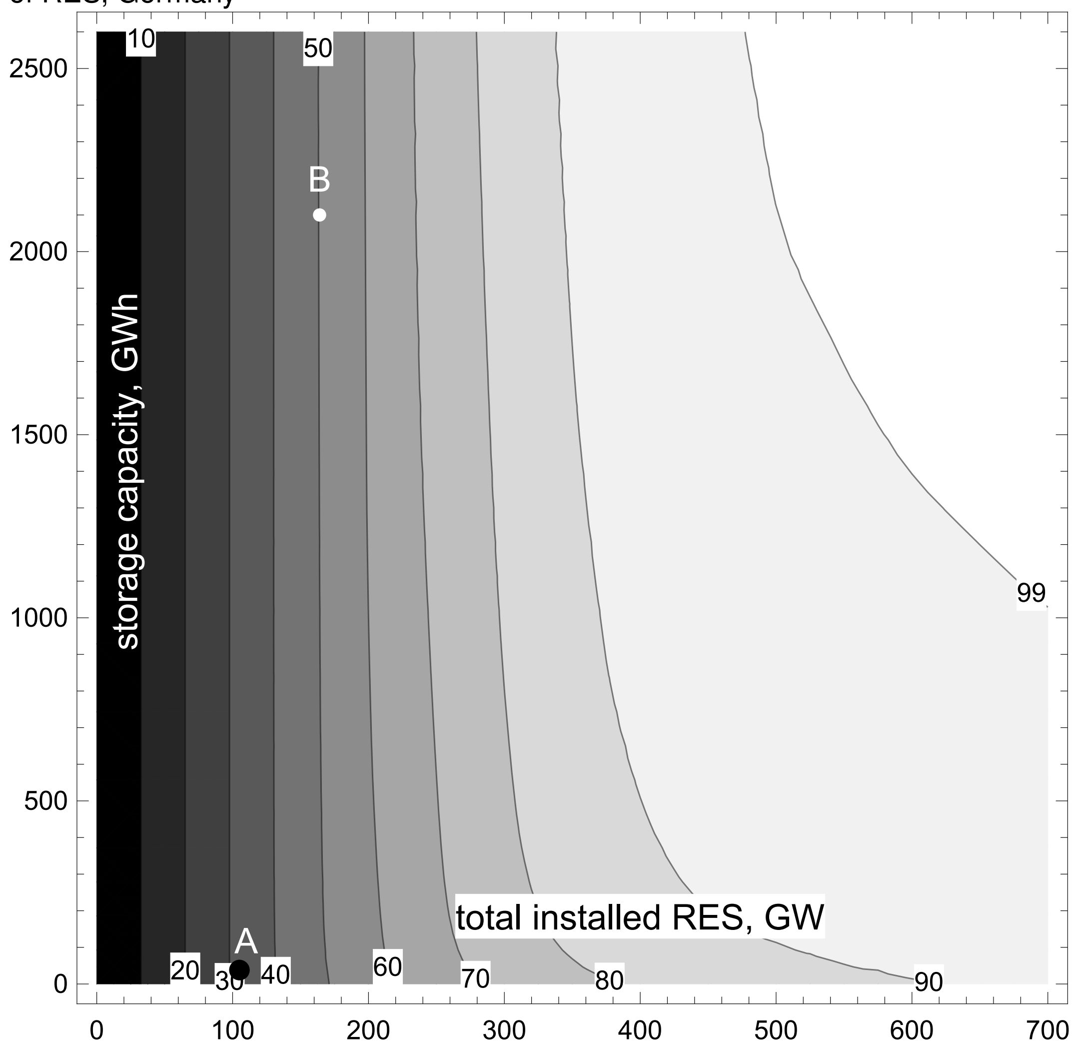
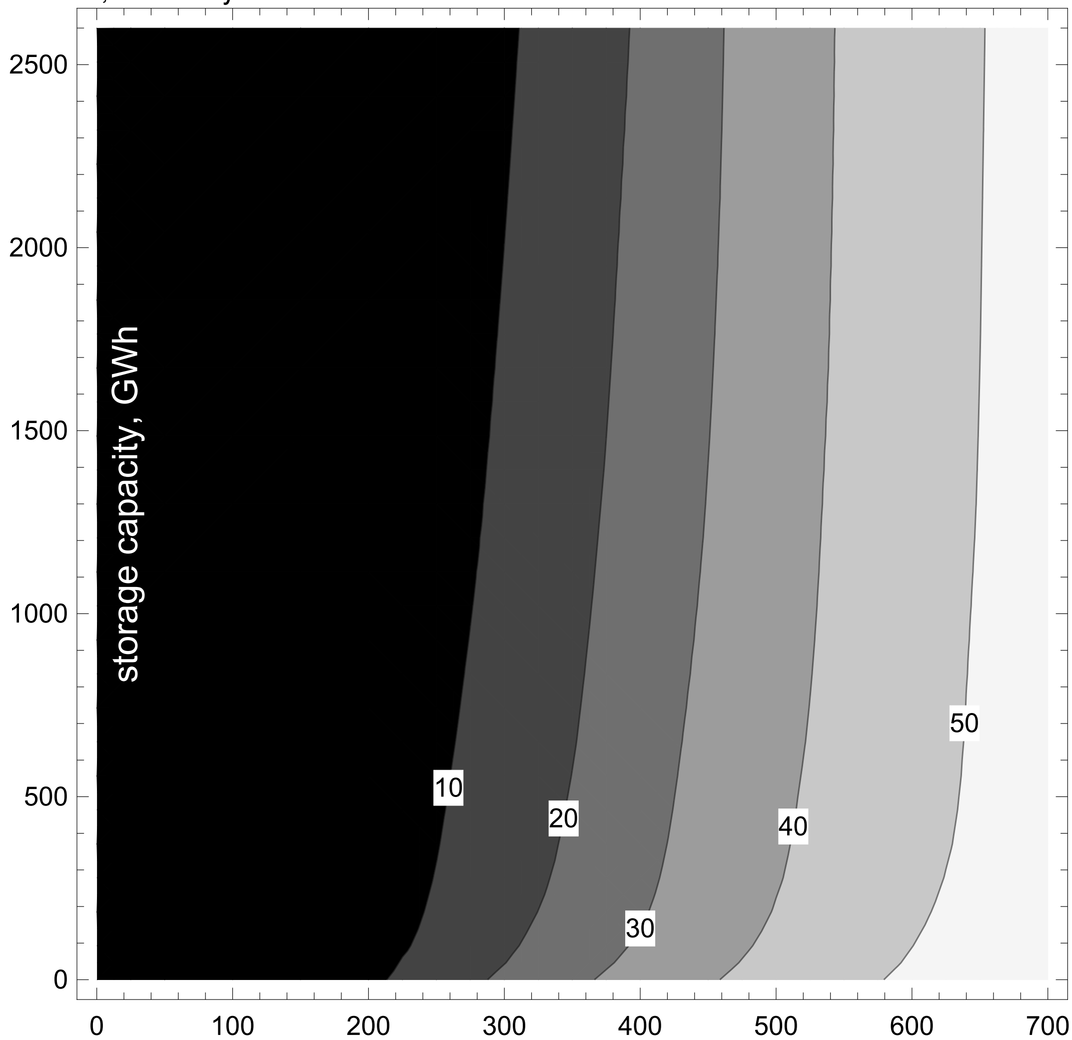


Figure C.2: Iso curves of RES curtailment (%), depending on storage and installed capacity of RES, Germany



High capacities of installed RES will lead to high curtailment rates, as table C.1 and figure C.2 show. At the same time, electrical storage of all RES surpluses at high RES penetration is, as demonstrated by Sinn (2017), not feasible (at least in terms of expansion of pumped storage). In the German network with limited transmission capacities high RES penetration will lead to high curtailment and high compensation payments, while elimination of compensation payments can reduce incentives to expand RES capacities. The existing legal framework in Germany will have to change to create incentives to utilize surplus RES energy, for example, by removing obstacles for the economic potential of power-to-heat (Romero, 2018).

C.2 Power system characteristics

Tables C.2-C.5 present output of myopic storage heuristic for combinations of installed RES and storage capacities. Tables C.2 and C.3 list RES penetration levels, while tables C.4 and C.5 list curtailment rates. There are no cross-border flows in tables C.2 and C.4, while in tables C.3 and C.5 there are no transmission constraints. All four tables are based on 2014 load and weather patterns.

Table C.2: RES penetration (%), autarky

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
250.	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
312.5	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9
375.	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
437.5	30.6	30.6	30.6	30.6	30.6	30.7	30.7	30.7	30.7	30.7	30.7
500.	34.7	34.8	34.8	34.9	34.9	34.9	34.9	35.	35.	35.	35.
562.5	38.6	38.7	38.8	38.9	39.	39.	39.	39.1	39.1	39.1	39.2
625.	42.3	42.4	42.6	42.7	42.8	42.9	42.9	43.	43.	43.1	43.1
687.5	45.7	46.	46.2	46.3	46.4	46.5	46.6	46.7	46.8	46.8	46.9
750.	49.	49.3	49.6	49.8	49.9	50.1	50.2	50.3	50.4	50.4	50.5
812.5	52.	52.4	52.7	53.	53.2	53.3	53.5	53.6	53.7	53.8	53.9
875.	54.8	55.3	55.7	56.	56.2	56.4	56.5	56.7	56.9	57.	57.1
937.5	57.3	58.	58.4	58.8	59.	59.3	59.5	59.6	59.8	60.	60.1
1000.	59.7	60.5	61.	61.4	61.7	62.	62.2	62.4	62.6	62.8	62.9
1062.5	61.9	62.8	63.4	63.8	64.2	64.5	64.8	65.	65.2	65.4	65.6
1125.	64.	64.9	65.6	66.1	66.5	66.9	67.2	67.5	67.7	67.9	68.1
1187.5	65.8	66.9	67.6	68.2	68.7	69.1	69.4	69.7	70.	70.2	70.5
1250.	67.6	68.7	69.5	70.2	70.7	71.2	71.5	71.9	72.2	72.4	72.7

Table C.3: RES penetration (%), copper plate

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
250.	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
312.5	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9
375.	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
437.5	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7
500.	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
562.5	39.5	39.5	39.5	39.5	39.5	39.5	39.5	39.5	39.5	39.5	39.5
625.	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
687.5	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2
750.	52.6	52.6	52.6	52.6	52.6	52.6	52.6	52.6	52.6	52.6	52.6
812.5	56.8	56.9	57.	57.	57.	57.	57.	57.	57.	57.	57.
875.	61.	61.1	61.2	61.3	61.3	61.3	61.4	61.4	61.4	61.4	61.4
937.5	64.9	65.2	65.4	65.5	65.5	65.6	65.6	65.7	65.7	65.7	65.8
1000.	68.6	68.9	69.2	69.3	69.5	69.6	69.7	69.8	69.9	69.9	70.
1062.5	71.9	72.4	72.7	72.9	73.1	73.3	73.4	73.5	73.6	73.8	73.8
1125.	75.	75.6	75.9	76.2	76.4	76.6	76.8	77.	77.2	77.3	77.4
1187.5	77.8	78.6	79.	79.3	79.6	79.8	80.	80.2	80.4	80.6	80.7
1250.	80.4	81.3	81.8	82.2	82.5	82.8	83.	83.2	83.4	83.6	83.7

Table C.4: RES curtailed (%), autarky

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
250.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
312.5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
375.	0.1	0.1	0.	0.	0.	0.	0.	0.	0.	0.	0.
437.5	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.	0.
500.	1.2	0.9	0.7	0.6	0.5	0.4	0.4	0.3	0.3	0.3	0.2
562.5	2.3	1.9	1.7	1.4	1.3	1.1	1.	0.9	0.9	0.8	0.7

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
625.	3.6	3.2	2.9	2.6	2.4	2.2	2.1	1.9	1.8	1.7	1.6
687.5	5.2	4.6	4.2	3.9	3.7	3.5	3.3	3.1	3.	2.9	2.7
750.	6.9	6.2	5.8	5.4	5.1	4.9	4.6	4.5	4.3	4.1	4.
812.5	8.8	8.	7.5	7.1	6.7	6.4	6.2	6.	5.8	5.6	5.4
875.	10.8	9.9	9.3	8.8	8.5	8.1	7.8	7.6	7.4	7.1	6.9
937.5	12.8	11.8	11.2	10.6	10.2	9.9	9.6	9.3	9.	8.8	8.6
1000.	14.8	13.8	13.	12.5	12.	11.6	11.3	11.	10.7	10.5	10.3
1062.5	16.9	15.8	15.	14.3	13.8	13.4	13.1	12.7	12.5	12.2	12.
1125.	19.	17.8	16.9	16.2	15.7	15.2	14.8	14.5	14.2	13.9	13.7
1187.5	21.	19.7	18.8	18.1	17.5	17.	16.6	16.3	15.9	15.7	15.4
1250.	22.9	21.7	20.7	19.9	19.3	18.8	18.4	18.	17.7	17.4	17.1

Table C.5: RES curtailed (%), copper plate

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
250.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
312.5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
375.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
437.5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
500.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
562.5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
625.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
687.5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
750.	0.1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
812.5	0.3	0.1	0.	0.	0.	0.	0.	0.	0.	0.	0.
875.	0.6	0.4	0.3	0.2	0.1	0.1	0.	0.	0.	0.	0.
937.5	1.3	0.9	0.6	0.4	0.3	0.3	0.2	0.1	0.1	0.	0.
1000.	2.2	1.7	1.4	1.2	0.9	0.8	0.6	0.5	0.4	0.3	0.2

RES	storage capacity, GWh										
GW	300	600	900	1200	1500	1800	2100	2400	2700	3000	3300
1062.5	3.5	2.8	2.4	2.2	1.9	1.7	1.5	1.3	1.2	1.	0.9
1125.	4.9	4.2	3.8	3.4	3.1	2.9	2.7	2.4	2.2	2.1	1.9
1187.5	6.6	5.7	5.2	4.8	4.5	4.2	3.9	3.7	3.5	3.3	3.1
1250.	8.3	7.3	6.7	6.3	5.9	5.6	5.3	5.1	4.9	4.7	4.5

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Appendix D

Technical Documentation

An interested reader can find the files on the CD accompanying the thesis.

D.1 Transmission capacities and competition in Western European electricity market

Chapter 1 is published in Spiridonova (2016). The computations in this chapter has been done in GAMS, building on the code and data from Gabriel and Leuthold (2010). The code itself is not published.

The mathematical formulation of the model, taken from Gabriel and Leuthold (2010), can be found in section 1.3. Gabriel and Leuthold (2010) consider only one strategic player and solve a corresponding mathematical program with equilibrium constraint (MPEC). I assume that the number of strategic players is larger than one and solve a system of MPECs, or an equilibrium problem with equilibrium constraints (EPEC). The solution EPEC is found by diagonalization (see Gabriel et al. (2013), chapter 7), described in section 1.3.

Model results were exported in .txt lists, that were imported in Mathematica code written by prof. Franz Hubert to produce maps in figures 1.1-1.5 in chapter 1.

D.2 Anticompetitive effects of RES infeed in a transmission-constrained network

The description on the methodology can be found in section 2.2 and appendix B.2.

The following subsections present the description of code files.

D.2.1 Marginal cost functions

To obtain marginal costs, we constructed a merit order curve for each node combining the information on conventional installed capacities in Germany, Austria and Luxembourg obtained via Open Power System Data (2016) and marginal costs estimations based on Egerer et al. (2014). The file **conventional_power_plants.sqlite** was downloaded from Open Power System Data (2016), `https://data.open-power-system-data.org/conventional_power_plants/2016-10-27`.

Next, the code contained in **conventional_power_plants_by_fuelnode.txt** was applied to **conventional_power_plants.sqlite** in in the DB Browser for SQLite. The data on conventional power plant was grouped by nodes and by fuel type used into a table "fuelsandnodes", marginal costs estimations for each fuel type were added based on Egerer et al. (2014). This information is presented in the table 2.2.

The SQLite table "fuelsandnodes" was exported into a separate file **conventional_power_plants_fuelsandnodes.csv** and read into Mathematica notebook **DE-Data-to-Parameters.nb**. For both nodes - North and South - we have obtained a very good fit for marginal cost with a simple polynomial having only a quadratic term ($mc(g) = c \cdot g^2$). The coefficients for the quadratic term are $c_N =$ 0.0904321 and $c_S =$ 0.0209779 for nodes North and South, respectively.

D.2.2 Demand calibration: reference points

We consider two reference points: mean and peak. In 2014 mean load was 66.2 GW, mean price - 32.8 €/MWh; peak load 86.2 GW, peak price - 52.9 €/MWh. For the peak demand scenario hourly loads in 2014 in the price zone of Germany, Austria and Luxembourg were sorted from highest to lowest. The peak reference point values refer to the mean load and price in the top 5% of hours with highest load. Load data comes from ENTSO-E (2018a), price data - form EEX. We do not have a permission to publish the EEX data set.

D.2.3 Demand calibration: inverse demand functions

Apart from estimating marginal cost functions, the Mathematica notebook **DE-Data-to-Parameters.nb** calculates intercept and slope parameters of linear inverse demand functions, passing through corresponding reference points. Next we decompose parameters for the whole market (Germany, Austria, and Luxembourg) into nodal parameters (nodes North and South). Since load is assumed to be distributed according to regional GDP, nodal demand intercepts are equal, while demand slopes are inversely proportional to the regional GDP shares. Resulting parameters are presented in table 2.1.

Nodal intercept and slope parameters of linear inverse demand functions and marginal cost coefficients are exported in files **DE-Parameters-Mean-Demand** and **DE-Parameters-Peak-Demand**.

D.2.4 Pure strategy equilibria

The Mathematica files **Pure-Strategy-EQ.nb** and **Pure-Strategy-EQ.m** provide the definitions of functions, that describe both best response functions and profits from producing best response. These functions are used in the search for the pure strategy equilibria given the parameter values.

The Mathematica notebook **PURE-working-space.nb** reads in **Pure-Strategy-EQ.m** and either **DE-Parameters-Mean-Demand** or **DE-Parameters-Peak-Demand**, to produce a table **tableGenerationPureEQpeak.txt** (**tableGenerationPureEQmean.txt**) containing equilibria type and equilibrium nodal outputs for a range of wind infeed and line capacities.

D.2.5 Mixed strategy equilibria

Mathematica notebook **MIXED-working-space** looks for mixed equilibria in the model, using approach described in Section B.2. This files uses:

1. **Pure-Strategy-EQ.m**,
2. **DE-Parameters-Peak-Demand** or **DE-Parameters-Mean-Demand** for the calibration of marginal costs,
3. **MIXED-DE-demand-peak-calibration.m** or **MIXED-DE-demand-mean-calibration.m** for the calibration of demand parameters,
4. finally, **MIXED-strategy.m** defines the algorithm used to find mixed equilibria (see appendix B.2).

Once the files listed above are read in, **MIXED-working-space** looks for a mixed equilibrium for a set of starting points and produces an output file (example: **resultsOfFoldings_k16_w13_peak.txt**, where the number after k indicates transmission capacity of the line, and the number after w - wind infeed, and *peak* refers to the demand scenario). The output files list mixed equilibria values for: output strategies of Northern player, output strategies of Southern player, profits of Northern player, profits of Southern player.

D.2.6 Analysis of pure and mixed strategy equilibria

The Mathematica notebook **DE-evaluation-of-EQ.nb** reads in files with both functions and parameters, for example for the peak calibration:

1. **Pure-Strategy-EQ.m**,
2. **MIXED-DE-demand-peak-calibration.m**,
3. **tableGenerationPureEQpeak.txt**,
4. mixed equilibria outputs for a certain level of line capacity (for example, **resultsOfFoldings_k16_w13_peak.txt**, **resultsOfFoldings_k16_w16_peak.txt**, **resultsOfFoldings_k16_w19_peak.txt**)

Once the files are read in, **DE-evaluation-of-EQ.nb** produces graphical outputs, presented in Section 2.4.2, mixed equilibria histograms in figure 2.4, and tables, presented in appendix B.3.

D.2.7 Wind generation in Germany, 2013-2016

Finally, probability density and cumulative distribution functions of wind generation in Germany in 2013-2016 in appendix B.1 are based on the data set **time_series_60min_singleindex_filtered.csv**, downloaded from Open Power System Data (2017), `https://data.open-power-system-data.org/time_series/2017-07-09`, filtered by region DE and by start date 2010-01-01. The calculations and plots have been performed in the Mathematica notebook **wind Density.nb**.

D.3 Spacial vs. temporal balancing: effects of transmission expansion and storage capacity on a European power system

The analysis have been performed within the Mathematica notebook **analysis_myopic_storage.nb**. The methodology is described in section 3.3. The data used:

1. Capacity factors were taken from the reanalysis studies by Staffell and Pfenninger (2016c) and Pfenninger and Staffell (2016). Files **ninja_wind_europe_v1.1_future_nearterm_national.csv**, **ninja_wind_europe_v1.1_current_national.csv**, **ninja_wind_europe_v1.1_future_nearterm_on-offshore.csv**, and **ninja_pv_europe_v1.1_merra2.csv** were downloaded (all in versions v1.1) at Renewables.ninja (2018). This data is not published, but can be downloaded by an interested reader from Renewables.ninja (2018). The only manual data manipulation, done outside of Mathematica notebook **analysis_myopic_storage.nb**, was the removal from the original .csv files of all the entries apart from those for the years 2012-2014;

2. Load data, recorded in **ENTSOE coreEU+ 12-14.dsf**, was downloaded from ENTSO-E (2018a). It was then refined by Domenico Schneider and Franz Hubert at the Chair for Management Science at Humboldt University of Berlin, with files **DataFormat.m** and **DataDocu.m** providing documentation. In the data set 4 entries (2 hours in year 2012, 1 hour 2013, and 1 hours in 2014) of Spanish load are missing and are replaced with average of load an hour before and after;

3. To be able to scale up installed renewable capacity, I assume that in the future the distribution of installed renewables within each country between different technologies – onshore, offshore wind and PV – will follow the structure in Fraunhofer IWES (2015), table 6, page 81. These capacity levels come from national grid development plans and national energy strategy documents (for Austria, Germany, France and partially the Netherlands), and from the "green transition" vision of ENTSO-E (2014) for the rest.

For my analysis, I need the capacity factors for wind offshore, onshore and solar generation in Germany, Austria, Belgium, Switzerland, Czech republic, Denmark, Spain, Finland, France, Great Britain, Hungary, Italy, the Netherlands, Norway, Poland, Portugal, Sweden, Slovenia and Slovakia.

For PV, Pfenninger and Staffell (2016) provide two capacity factors datasets, based on two different meteorological sources: NASA's MERRA-2 and Meteosat-based CM-SAF SARAH. However, Pfenninger and Staffell (2016) state that MEERA-2 version is more consistent on a long-term basis. Hence I use this data, recorded in **ninja_pv_europe_v1.1_merra2.csv**.

For wind, Staffell and Pfenninger (2016c) provide "near-term" future capacity factors for on- and offshore wind in **ninja_wind_europe_v1.1_future_nearterm_on-offshore.csv**, where "near-term" future wind fleet refers to current wind fleet (operating wind fleet as of December 2016) plus under construction or with planning approval as of December 2016 (see Readme file at Renewables.ninja (2018)). File **ninja_wind_europe_v1.1_future_nearterm_national.csv** provides national "near-term" future capacity factors for wind, without on-/offshore division. Since **ninja_wind_europe_v1.1_future_nearterm_on-offshore.csv** file does not cover all wind types (on- and ofshore) for all of the 19 considered countries, additional assumptions have been made:

1. For land locked countries, offshore wind capacities factors are set to zero (Austria, Switzerland, Czech republic, Hungary, Poland, Slovenia and Slovakia);
2. Onshore wind capacity factors for Switzerland, Czech republic, Hungary, Portugal, Slovenia and Slovakia are missing both from **ninja_wind_europe_v1.1_future_nearterm_on-offshore.csv** and **ninja_wind_europe_v1.1_future_nearterm_national.csv**, hence I take them from **ninja_wind_europe_v1.1_current_national.csv** - a national wind capacity factor data set based on "current" wind fleet characteristics (operating wind fleet as of December 2016, see Readme file at Renewables.ninja (2018));
3. Denmark has only offshore wind capacity factors in **ninja_wind_europe_v1.1_future_nearterm_on-offshore.csv**, hence I set its onshore wind capacity factors equal to its national wind capacity factors from **ninja_wind_europe_v1.1_future_nearterm_national.csv**;
4. Fraunhofer IWES (2015) lists future wind offshore capacity in Spain and Portugal as equal to zero. Hence offshore wind capacity factors in there countries are set to zero.

Days with time change (summer to winter time, winter to summer time) were removed from analysis.

Taking the data, described above, the Mathematica notebook **analysis_myopic_storage.nb** performs two types of calculations ("chapters" within the file **analysis_myopic_storage.nb**).

The first step assumes no storage in the network, and looks for installed RES capacity (in GW) required to reach certain RES penetration targets (see subsection 3.5.1 and appendix and C.1). The second step assumes a myopic storage heuristic, described in described in section 3.3. Any current RES output exceeding load is stored as long as the storage capacity permits and is curtailed otherwise. Once residual load – the difference between load and RES generation – is positive, energy is released from storage, displacing conventional generation. The myopic storage heuristic takes an installed RES capacity and a storage capacity and provides an output in form of a time series of conventional dispatch, RES curtailment and energy stored (i.e., hourly storage levels). These time series are then used to calculate system characteristics, reported in chapter 3 and appendix C.2.

Erklärung zu verwendeten Hilfsmittel

Ich bezeuge durch meine Unterschrift, dass meine Angaben über die bei der Abfassung meiner Dissertation benutzten Hilfsmittel, über die mir zuteil gewordene Hilfe sowie über frühere Begutachtungen meiner Dissertation in jeder Hinsicht der Wahrheit entsprechen.

Berlin, den 29. March 2019 | Olga Spiridonova